Air Quality Permitting
Statement of Basis

September 6, 2005

Permit to Construct No. P-040404

Glanbia Foods, Inc.
Gooding, Idaho

Facility ID No. 047-00008

Prepared by:

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AIR QUALITY DIVISION

FINAL PTC

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Acronyms, Units, and Chemical Nomenclatures

AFS	AIRS Facility Subsystem
AIRS	Aerometric Information Retrieval System
AQCR	Air Quality Control Region
ASTM	American Society for Testing and Materials
Btu/scf	British thermal unit per standard cubic foot
CFR	Code of Federal Regulations
CO	carbon monoxide
DEQ	Department of Environmental Quality
EPA	U.S. Environmental Protection Agency
gal/yr	gallons per year
gr/dscf	grains per dry standard cubic feet
H_2S	hydrogen sulfide
HAPs	Hazardous Air Pollutants
hr/day	hours per day
hr/yr	hours per year
IDAPA	a numbering designation for all administrative rules in Idaho promulgated in accordance with the Idaho Administrative Procedures Act
kW	kilowatt
lb/hr	pound per hour
MACT	Maximum Achievable Control Technology
$\mu g/m^3$	micrograms per meter cubed
MMBtu/hr	million British thermal units per hour
NESHAP	National Emission Standards for Hazardous Air Pollutants
NO_2	nitrogen dioxide
NO_x	nitrogen oxides
NSPS	New Source Performance Standards
O&M	Operations and Maintenance
PM	particulate matter
PM_{10}	particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
ppmv	parts per million by volume
PSD	Prevention of Significant Deterioration
PTC	permit to construct
PTE	potential to emit
SIC	Standard Industrial Classification
SM	Synthetic Minor
SO_2	sulfur dioxide
SO_x	sulfur oxides
T/yr	tons per any consecutive 12 month period
UTM	Universal Transverse Mercator
VOC	volatile organic compound
wt%	weight percent

1. PURPOSE

The purpose for this memorandum is to satisfy the requirements of IDAPA 58.01.01.200, Rules for the Control of Air Pollution in Idaho, for issuing permits to construct.

2. FACILITY DESCRIPTION

Glanbia Foods, Inc. (Glanbia) operates a facility near Gooding that manufactures cheese and whey dairy-based products from raw milk.

3. FACILITY / AREA CLASSIFICATION

This facility is not a major facility as defined by IDAPA 58.01.01.205 because its potential to emit is limited to less than the applicable major source trigger, 250 T/yr. The facility is not a designated facility as defined by IDAPA 58.01.01.006.27. The facility is subject to federal NSPS requirements in accordance with 40 CFR 60, Subpart Dc. At this time, the facility is not subject to federal NESHAP requirements in accordance with 40 CFR 61 and 63. The SIC code defining the facility is 2022, *Natural, Processed, and Imitation Cheese*. The AIRS facility classification is "SM." The AIRS data entry table is provided as Appendix A.

This facility is located within AQCR 63 and UTM zone 11. The facility is located in Gooding County which is classified as unclassifiable for all criteria air pollutants.

4. APPLICATION SCOPE

Glanbia has submitted a PTC application for the construction of a biogas/natural gas-fired hot water boiler (auxiliary boiler) and a biogas flare. Both will be used to control emissions from an anaerobic digester that is used to further treat process wastewater prior to discharge. The anaerobic digester will generate biogas that can be burned in the auxiliary boiler or in the flare. The auxiliary boiler will be used to heat the influent wastewater for the anaerobic digester. If not enough biogas is available to fire the auxiliary boiler, natural gas will be used as the fuel for the boiler and all the biogas will be burned in the flare. If the boiler is not operational the flare will incinerate the biogas. The pilot light for the flare will only operate intermittently when the biogas pressure drops below a certain level.

Glanbia has also requested that DEQ further limit the facility's four process boilers previously permitted under PTC No. 047-00008, issued May 7, 2000. This permit regulates the operations of the four process boilers to maintain the facility's synthetic minor status and SO_2 NAAQS compliance. Distillate fuel oil is the backup fuel for the process boilers. Glanbia has requested that DEQ reduce the allowable amount of distillate fuel oil combusted in the boilers and reduce the sulfur content limit of the fuel oil to 0.05 wt%. These reductions are required to retain the facility's synthetic minor status and SO_2 NAAQS compliance.

4.1 *Application Chronology*

June 22, 2004	DEQ received a 15-day pre-permit construction approval PTC application from Power Engineers, on behalf of Glanbia.
July 6, 2004	DEQ determined the application incomplete and denied pre-permit construction approval.
July 26, 2004	DEQ received a submittal from Power Engineers on behalf of Glanbia in response to the incompleteness determination.

August 2, 2004	DEQ received additional information and modeling files from Power Engineers on behalf of Glanbia.
August 4, 2004	DEQ issued notice of pre-permit construction approval to Glanbia.
August 25, 2004	DEQ declared the application incomplete.
February 7, 2005	DEQ received an application submittal from CH2M HILL on behalf of Glanbia in response to the incompleteness determination.
March 9, 2005	DEQ declared the application complete.
March 16, 2005	DEQ received additional information and revised modeling files from CH2M HILL on behalf of Glanbia.
May 16, 2005	DEQ received revised modeling files from CH2M HILL on behalf of Glanbia.
July 12, 2005	DEQ received revised emission estimates from CH2M HILL on behalf of Glanbia.
September 6, 2005	DEQ received email notification from Glanbia withdrawing the request to review a facility draft of the PTC.

5. PERMIT ANALYSIS

This section of the Statement of Basis describes the regulatory requirements for this PTC action.

5.1 Equipment Listing

Table 5.1 includes all emissions units at this facility, including the new units associated with this PTC project.

Table 5.1 GLANBIA FOODS (GOODING) EQUIPMENT LISTING

Source Description	Emissions Control(s)
__Anaerobic digester__ Designed by the Biothane Corporation	**Biogas flare (Flr 1)** Manufacturer: Varec Biogas Model: No. 244 W Rated Heat Input Capacity: 11.75 MMBtu/hr Date of Installation: 2005
Auxiliary Boiler (Blr 5) Manufacturer: Cleaver Brooks Model No.: CB700-400-30H Rated Heat Input Capacity: 16.7 MMBtu/hr Fuels: Biogas and/or natural gas Date of Installation: 2005	None (considered an emission control device for the anaerobic digester when combusting biogas)
__Process Boilers (Existing)__ **Boiler 1 (Blr 1)** Rated Heat Input Capacity: 29.35 MMBtu/hr Manufacturer: Continental Model No.: E Series, E162A700C-7685-G2A Fuel: Natural gas exclusively Date of Installation: July 1979	None
Boiler 2 (Blr 2) Rated Heat Input Capacity: 25.1MMBtu/hr Manufacturer: Cleaver Brooks Model No.: CB600-600 Serial No.: L-90943 Fuels: Low sulfur distillate fuel oil or natural gas Date of Installation: July 1992	Annual distillate fuel oil throughput limit and distillate fuel oil sulfur content limit

Source Description	Emissions Control(s)
Boiler 3 (Blr 3) Rated Heat Input Capacity: 25.1MMBtu/hr Manufacturer: Cleaver Brooks Model No.: CB600-600 Serial No.: L-79896 Fuels: Low sulfur distillate fuel oil or natural gas Date of Installation: December 1996	Annual distillate fuel oil throughput limit and distillate fuel oil sulfur content limit
Boiler 4 (Blr 4) Rated Heat Input Capacity: 25.1MMBtu/hr Manufacturer: Cleaver Brooks Model No.: CB600-600 Serial No.: L-79895 Fuels: Natural gas exclusively Date of Installation: December 1999	None
WPC Dryer Rated Heat Input Capacity: 9.2 MMBtu/hr Manufacturer: Not listed Model No.: Direct fire burner Serial No.: Unknown Fuel: Natural gas Date of Installation: 1996	None
Emergency Backup Electrical Generator Rated Capacity: 815 kW Manufacturer: Cummins/Onan Model No.: Generator: 3377624G Generator Engine: 25247994 Serial No.: J990000184 Fuel: Distillate fuel Date of Installation: 1999	None
Heater 1 Rated Heat Input Capacity: 1.5 MMBtu/hr Manufacturer: Reznor Model No.: RDF2-120 Serial No.: AQB61K2N062931 Fuel: Natural gas Date of Installation: 1990	None
Heater 2 Rated Heat Input Capacity: 5.89 MMBtu/hr Manufacturer: Industrial Commercial Equipment Model No.: DMA1233MODEDA Serial No.: 24306D9910 Fuel: Natural gas Date of Installation: 1998	None
Heater 3 Rated Heat Input Capacity: 1.374 MMBtu/hr Manufacturer: Industrial Commercial Equipment Model No.: Not listed Serial No.: 243069B991C Fuel: Natural gas Date of Installation: 2000	None

5.2 *Emissions Inventory*

Appendix B contains the permittee's summary of the project's air emissions inventory. The criteria air pollutant emission inventory is summarized in Table 5.2 for the emissions from this project. Emissions of lead, also a criteria air pollutant, are listed in the TAPs emissions inventory in the Table 5.3. The values shown are those listed in the permit application.

Criteria Air Pollutants

Natural Gas and Distillate Fuel Oil Combustion

The permittee estimated criteria air pollutant emissions resulting from the combustion of natural gas for Boilers 1, 2, 3, and 4; the WPC Dryer; and Heaters 1, 2, and 3 using emission factors from U.S. EPA AP-42, Section 1.4, *Natural Gas Combustion*, July 1998. Emissions of criteria air pollutants were assumed to be uncontrolled. The heat content of natural gas used by the applicant was 1,056 Btu/scf, as provided by the Intermountain Gas Company.

Criteria air pollutant emissions for combustion of distillate fuel oil were estimated using U.S. EPA AP-42, Section 1.3, September 1998. Emissions for the backup electrical generator engine were estimated using U.S. EPA AP-42, Section 3.4, *Large Stationary Diesel and All Stationary Dual-fuel Engines*, October 1996. The generator was assumed to operate 500 hr/yr, consistent with EPAs guidance for determining potential to emit for emergency generators.

Sulfur dioxide emissions for Boilers 2 and 3 were estimated using distillate fuel (ASTM Grades 1 or 2) with a maximum sulfur content of 0.05 wt%. The emissions inventory reflects operation of both Boilers 2 and 3 firing low sulfur distillate fuel oil concurrently for 24 hr/day. Annual emission estimates for these boilers were based on 1,080 hours of operation, or 193,629 gallons per year of distillate fuel oil consumption for each boiler. Glanbia has requested that the total amount of low sulfur distillate fuel oil be limited to a total amount of 387,258 gallons per year, which could be combusted by Boiler 1 or 2 individually or collectively.

For documentation purposes, distillate fuel oil combustion is being reduced from 2,760,563 gallons per year to 387,258 gallons per year, and the fuels sulfur content is being reduced from 0.5 wt% to 0.05 wt%. These reductions are required to retain the facility's synthetic minor status and SO_2 NAAQS compliance.

Anaerobic Digester

The emissions from the anaerobic digester are to be controlled by either of two methods. The primary control method is to combust the biogas in the auxiliary boiler, and the alternative method is with the flare. The auxiliary boiler and the flare will not operate concurrently. The flare is a backup control device that will incinerate the biogas in the event the auxiliary boiler is off-line for biogas combustion.

According to the permittee's application materials, the anaerobic digester is expected to produce a maximum 433,823 scf per day of biogas. The daily production rate averages out to be 18,076 scf per hour based on operating 24 hr/day. The biogas is anticipated to contain a heat content of 650 Btu/scf, and a hydrogen sulfide concentration in the biogas of 2,297 ppmv. The anticipated H_2S concentration and biogas generation rate result in the potential generation of 3.6 lb/hr of H_2S. When reacted in a combustion process, the sulfur in the H_2S is a source of SO_2 emissions. H_2S is a TAP, while SO_2 is a criteria air pollutant.

The permittee assumed that the auxiliary boiler has a 98% destruction efficiency for H_2S and a 100% conversion of H_2S to SO_2 emissions. This results in all available sulfur in the biogas being emitted as SO_2 for a worst-case estimate of SO_2 emissions.

Emissions of NOx, CO, and VOCs from the biogas flare were estimated using AP-42, Section 13.5, *Industrial Flares*, September 1991. PM and PM10 emissions for the flare were estimated using AP-42, Section 1.4, *Natural Gas Combustion*, July 1998. SO_2 emissions were estimated assuming a 90% control efficiency for H_2S for biogas and a 90% conversion of sulfur to SO_2 emissions for the natural gas fuel for the flare's pilot flame.

Emission factors and emission estimates provided by the permittee appeared appropriate based on DEQ's review. A summary of the criteria air pollutant emissions for this project is listed in Tables 5.2 and 5.3.

Table 5.2 CRITERIA AIR POLLUTANT EMISSION INVENTORY-FACILITY-WIDE COMBUSTION SOURCES

Source	PM/PM_{10}[a]		SO_2[b]		VOC[c]		NO_x[d]		CO[e]	
	(lb/hr)[f]	(T/yr)[g]	(lb/hr)	(T/yr)	(lb/hr)	(T/yr)	(lb/hr)	(T/yr)	(lb/hr)	(T/yr)
Biogas Flare[h]	0.09	0.37	6.11	26.76	0.74	3.24	0.80	3.50	4.35	19.04
Boiler 1 - Natural Gas	0.21	0.92	0.02	0.07	0.15	0.67	2.78	12.17	2.33	10.22
Boiler 2 – Dual Fuel (Natural Gas)	0.18	0.69	0.01	0.05	0.13	0.50	2.38	9.12	2.00	7.66
Boiler 3 – Dual Fuel (Natural Gas)	0.18	0.69	0.01	0.05	0.13	0.50	2.38	9.12	2.00	7.66
Boiler 2 - Dual Fuel (Distillate Fuel Oil)	0.36	0.19	1.27	0.69	0.10	0.05	3.59	1.94	0.90	0.48
Boiler 3 - Dual Fuel (Distillate Fuel Oil)	0.36	0.19	1.27	0.69	0.10	0.05	3.59	1.94	0.90	0.48
Boiler 4 – Natural Gas	0.18	0.79	0.01	0.06	0.13	0.57	2.38	10.41	2.00	8.74
Boiler 5[i]	0.17	0.73	6.87	30.11	0.27	1.17	1.98	8.65	2.51	11.00
WPC Dryer	0.07	0.29	0.01	0.02	0.05	0.21	0.87	3.81	0.73	3.20
Backup Electrical Generator	0.57	0.06	2.88	0.29	0.51	0.05	18.23	1.82	4.84	0.48
Heater 1	0.01	0.05	0.001	0.004	0.008	0.03	0.14	0.62	0.12	0.52
Heater 2	0.04	0.19	0.003	0.01	0.03	0.13	0.56	2.44	0.47	2.05
Heater 3	0.01	0.04	0.001	0.003	0.007	0.03	0.13	0.57	0.11	0.48
Total (worst-case):[j]	**2.78**	**5.22**	**14.88**	**32.06**	**1.90**	**7.23**	**25.80**	**66.12**	**18.89**	**72.04**

a) Particulate Matter/Particulate Matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers
b) Sulfur dioxide
c) Volatile Organic Compounds
d) Nitrogen oxides
e) Carbon monoxide
f) Pounds per hour
g) Tons per year
h) Worst-case SO_2 emissions are emitted by Boiler 5 combusting biogas (flare is not operated concurrently with Boiler 5 when Boiler 5 is combusting biogas). Flare emissions are included in the facility combustion units total potential to emit for VOCs and CO.
i) Biogas heat input is 11.75 MMBtu/hr and natural gas heat input is 5.0 MMBtu/hr for a total of 16.75 MMBtu/.hr for Boiler 5. Natural gas and biogas combustion emission rates must be added to quantify the potential emissions of Boiler 5.

Table 5.3 LEAD EMISSION INVENTORY-FACILITY-WIDE COMBUSTION SOURCES

Source	Lead	
	(lb/hr)[a]	(T/yr)[b]
Biogas Flare	-	-
Boiler 1 - Natural Gas	1.39E-05	6.09E-05
Boiler 2 – Dual Fuel (Natural Gas)	1.19E-05	4.56E-05
Boiler 3 – Dual Fuel (Natural Gas)	1.19E05	4.56E-05
Boiler 2 - Dual Fuel (Distillate Fuel Oil)	2.26E-04	1.22E-04
Boiler 3 - Dual Fuel (Distillate Fuel Oil)	2.26E-04	1.22E-04
Boiler 4 – Natural Gas	1.19E-05	5.20E-05
Boiler 5	7.92E-06	3.47E-05
WPC Dryer	4.35E-06	1.91E-05
Backup Electrical Generator	5.13E-05	5.13E-06
Heater 1	7.10E-07	3.11E-06
Heater 2	2.79E-06	1.22E-05
Heater 3	6.50E-07	2.85E-06
Total	**9.97E-04**	**5.25E-04**

a) Pounds per hour
b) Tons per year

TAPs

Emission estimates of TAPs from combustion of biogas for the flare and the auxiliary boiler were estimated using emission factors the "General Instruction Book for the AQMD 2003-2004 Annual Emissions Reporting Program" South Coast Air Quality Management District. TAPs emission factors from AP-42, Section 1.4, *Natural Gas Combustion*, July 1998, were used to estimate TAPs emissions for the combustion of natural gas from the auxiliary boiler. Worst-case TAPs emissions were estimated for the auxiliary boiler operating at rated capacity using assuming either combustion of 16.75 MMBtu/hr of natural gas or 11.75 MMBtu/hr of biogas and 5 MMBtu/hr of natural gas.

The permittee estimated TAPs emissions for Boilers 2, 3, and 5 and the biogas-fired flare. According to IDAPA 58.01.01.210, only the TAPs emissions for Boiler 5 and the biogas-fired flare are required to demonstrate compliance with the TAPs increments. Boilers 2 and 3 were already permitted to combust low sulfur distillate fuel oil in a PTC issued earlier. This project reduces the quantities of distillate fuel oil that both Boiler 2 and 3 are allowed to combust. Therefore, this project actually results in a net reduction in TAPs emissions for the combustion of distillate fuel oil. By including the TAPs emissions for distillate fuel oil combustion the permittee has presented a conservative demonstration of TAPs compliance.

TAPs emissions for combustion of distillate fuel oil in the process boilers were estimated using EPA AP-42, Section 1.3, *Fuel Oil Combustion*, September 1998. Emission factors and emission estimates appeared appropriate based on DEQ review.

Table 5.4 TAPs EMISSION INVENTORY–COMBUSTION SOURCES

Pollutant	Boiler 2 – Dual Fuel (Distillate Fuel Oil)		Boiler 3 – Dual Fuel (Distillate Fuel Oil)		Boiler 5 – (Biogas as primary and natural gas as secondary fuel)[f]		Biogas Flare		TOTAL	
	(lb/hr)[c]	(T/yr)[d]	(lb/hr)[c]	(T/yr)[d]	(lb/hr)[c]	(T/yr)[d]	(lb/hr)[c]	(T/yr)[d]	(lb/hr)[c]	(T/yr)[d]
3-Methylchloroanthrene	-	-	-	-	2.85E-8	1.25E-7	-	-	2.85E-8	1.25E-7
Benzene	3.84E-5	2.07E-5	3.84E-5	2.07E-5	1.15E-4	5.02E-4	2.87E-3	1.26E-2	3.07E-3	3.61E-3
Benzo(a)pyrene	-	-	-	-	1.90E-8	8.33E-8	-	-	1.90E-8	8.33E-8
Ethylbenzene	1.14E-5	6.16E-6	1.14E-5	6.16E-6	-	-	-	-	2.28E-5	1.23E-5
Formaldehyde	-	-	-	-	1.19E-3	5.20E-3	2.11E-2	9.26E-2	2.23E-2	9.78E-2
Hexane	-	-	-	-	2.85E-2	1.25E-1	-	-	2.85E-2	1.25E-1
Methyl chloroform	4.23E-5	2.28E-5	4.23E-5	2.28E-5	-	-	-	-	8.46E-5	4.56E-5
Naphthalene	2.03E-4	1.09E-4	2.03E-4	1.09E-4	9.67E-6	4.23E-5	-	-	4.15E-4	2.60E-4
Pentane	-	-	-	-	4.12E-2	1.81E-1	-	-	4.12E-2	1.81E-1
Polycyclic Organic Matter (POM)	5.92E-4	3.19E-4	5.92E-4	3.19E-4	-	-	-	-	1.18E-3	6.38E-4
Toluene	1.11E-3	6.00E-4	1.11E-3	6.00E-4	5.39E-5	2.36E-4	-	-	2.28E-3	1.44E-3
o-Xylene	1.95E-5	1.06E-5	1.95E-5	1.06E-5	-	-	-	-	3.91E-5	2.12E-5
Polyaromatic hydrocarbons (PAHs)	-	-	-	-	7.23E-6	3.17E-5	2.53E-4	1.11E-3	2.60E-4	1.14E-3
Ammonia	-	-	-	-	5.78E-2	2.53E-1	5.78E-2	2.53E-1	1.16E-1	5.06E-1
Hydrogen Sulfide	-	-	-	-	7.22E-2	3.16E-1	3.61E-1	1.58E+0	4.33E-1	1.896
TAPs (Metals)										
Arsenic	1.00E-4	5.42E-5	1.00E-4	5.42E-5	3.17E-6	1.39E-5	-	-	2.04E-4	1.22E-4
Barium	-	-	-	-	6.97E-5	3.05E-4	-	-	6.97E-5	3.05E-5
Beryllium	7.53E-5	4.07E-5	7.53E-5	4.07E-5	1.90E-7	8.33E-7	-	-	1.51E-4	8.22E-5
Cadmium	7.53E-5	4.07E-5	7.53E-5	4.07E-5	1.74E-5	7.64E-5	-	-	1.68E-4	1.58E-4
Chromium	7.53E-5	4.07E-5	7.53E-5	4.07E-5	2.22E-5	9.72E-5	-	-	1.73E-4	1.79E-4
Cobalt	-	-	-	-	1.33E-6	5.83E-6	-	-	1.33E-6	5.83E-6
Copper	1.51E-4	8.13E-5	1.51E-4	8.13E-5	1.35E-5	5.90E-5	-	-	3.15E-4	3.61E-4
Manganese	1.51E-4	8.13E-5	1.51E-4	8.13E-5	6.02E-6	2.64E-5	-	-	3.07E-4	3.28E-4
Mercury	7.53E-5	4.07E-5	7.53E-5	4.07E-5	4.12E-6	1.81E-5	-	-	1.55E-4	9.95E-5
Molybdenum	-	-	-	-	1.74E-5	7.64E-5	-	-	1.74E-5	7.64E-5
Nickel	7.53E-5	4.07E-5	7.53E-5	4.07E-5	3.33E-5	1.45E-4	-	-	1.84E-4	2.26E-4
Selenium	3.77E-4	2.03E-4	3.77E-4	2.03E-4	3.80E-7	1.67E-6	-	-	7.53E-4	4.08E-4
Vanadium	-	-	-	-	3.65E-5	1.60E-4	-	-	3.65E-5	1.60E-4
Zinc	1.00E-4	5.42E-5	1.00E-4	5.42E-5	4.60E-4	2.01E-3	-	-	6.60E-4	2.12E-3

5.3 Modeling

The permittee conducted modeling analysis for the proposed project. Predicted ambient impacts of SO_2 exceeded the significant contribution level, requiring a full impact analysis. The predicted ambient impacts for SO_2 associated with the proposed project are listed below in Table 5.5. The permittee conducted modeling of emission of each TAP where the project's emission rate exceeded the screening emission rate limits specified in IDAPA 58.01.01.585 and IDAPA 58.01.01.586. The results of the TAPs modeling are presented in Table 5.6. The detailed DEQ review memorandum of the modeling analysis is contained in Appendix C of this memorandum.

Table 5.5 FACILITY CONCENTRATIONS FOR CRITERIA POLLUTANTS FOR FULL IMPACT ANALYSIS

Pollutant	Averaging Period	Facility Ambient Concentration ($\mu g/m^3$)[a]	Total Ambient concentration[b] ($\mu g/m^3$)[a]	Percent of NAAQS[c]
SO_2	3-hour	323	357	27
	24-hour	150	174	47
	Annual	45	53	66

[a] Micrograms per cubic meter.
[b] Includes background concentration and facility impact.
[c] National Ambient Air Quality Standard

Table 5.6 TOXIC AIR POLLUTANTS ANALYSIS RESULTS

Pollutant	*Averaging Period*	**Maximum *Concentration* ($\mu g/m^3$)**	**Regulatory *Limit* (ug/m^3)**	**Percent of Limit**
Carcinogens				
Arsenic	Annual	1.3E-04	2.3E-04	57
Benzene	Annual	7.2E-02	1.2E-01	60
Beryllium	Annual	1.0E-04	4.2E-03	2
Cadmium	Annual	1.0E-04	5.6E-04	18
Formaldehyde	Annual	5.3E-02	7.7E-02	69
Nickel	Annual	1.5E-04	4.2E-03	4
Total PAH	Annual	6.3E-04	1.4E-02	4.5

5.4 Regulatory Review

This section describes the regulatory analysis of the applicable air quality rules with respect to this PTC.

IDAPA 58.01.01.201 .... Permit to Construct Required

This project involves the construction of a new biogas and natural gas-fired auxiliary boiler and a biogas-fired flare to control emissions from a newly-constructed wastewater treatment plant with an anaerobic digester at the facility. The project does not meet the exemption criteria contained in any Sections 220 through 223 of the Rules; therefore, a PTC is required.

IDAPA 58.01.01.210 .... Demonstration of Preconstruction Compliance with Toxic Standards

Uncontrolled emissions of H_2S exceed the screening emissions limit specified by IDAPA 58.01.01.585. Uncontrolled H_2S emissions are 3.6 lb/hr. The permittee submitted emissions estimates for controlled emissions for both the flare and the auxiliary boiler. Therefore, the method the permittee used to demonstrate compliance with IDAPA 58.01.01.210 for H_2S, was by providing controlled emissions, per IDAPA 58.01.01.210.07. Uncontrolled emissions were not used in the ambient impact analysis; therefore, it was assumed that the permittee demonstrated compliance with the AACC using a controlled ambient concentration per IDAPA 58.01.01.210.08, which requires an emission limit to be included in the PTC per IDAPA 58.01.01.210.08.c.

Emissions of all carcinogenic TAPs for this project that exceeded the screening emission rate limits specified in IDAPA 58.01.01.586 were modeled to demonstrate that predicted ambient impacts did not exceed the AACC for each pollutant. The carcinogenic TAP emissions from the flare and the auxiliary boiler are products of combustion and are not controlled by any additional air pollution control equipment.

The permittee provided conservative TAPs emission estimates for dual fuel Boilers 2 and 3 for distillate fuel oil combustion. Boilers 2 and 3 were already permitted to combust distillate fuel oil in greater annual quantities than requested in this PTC project. No additional permit conditions for TAPs emissions are warranted for distillate fuel oil combustion in Boilers 2 and 3 due to the permitting history of these boilers.

Table 5.7 lists the emission rates of each TAP analyzed for TAPs compliance.

Table 5.7 TOXIC AIR POLLUTANTS ANALYSIS RESULTS

Pollutant	Averaging Period	Project Emission Rate (lb/hr) [a]	Screening Emission Rate Limit (lb/hr)	Maximum Concentration ($\mu g/m^3$)[b]	Regulatory Limit ($\mu g/m^3$)	Percent Of Limit
Non-carcinogens						
Hydrogen Sulfide (H_2S)	24-hour	0.36[c]	0.933	NA	700.	NA
Carcinogens						
Arsenic	Annual	2.04E-4	1.5E-6	1.3E-04	2.3E-04	57
Benzene	Annual	3.07E-3	8.0E-4	7.2E-02	1.2E-01	60
Beryllium	Annual	1.51E-4	2.8E-5	1.0E-04	4.2E-03	2
Cadmium	Annual	1.68E-4	3.7E-6	1.0E-04	5.6E-04	18
Formaldehyde	Annual	2.23E-2	5.1E-4	5.3E-02	7.7E-02	69
Nickel	Annual	1.84E-4	2.7E-5	1.5E-04	4.2E-03	4
Total PAH	Annual	2.60E-4	9.1E-5	6.3E-04	1.4E-02	4.5

a) pounds per hour

b) micrograms per cubic meter

c) The listed emission rate is a controlled emission rate of H_2S from the flare, which is greater than the controlled emission rate of 0.072 lb/hr of H_2S for Auxiliary Boiler 5. Uncontrolled emissions of H_2S were estimated to be 3.6 lb/hr.

IDAPA 58.01.01.300................Procedures and Requirements for Tier I Operating Permits

Glanbia's Gooding facility is a synthetic minor Tier I source. Enforceable limitations were taken on PM_{10} and SO_2 emissions that are below the applicability thresholds. This facility has never been issued a Tier I permit. This permitting action will result in reduced SO_2 emissions for the existing process boilers at the facility, and with the SO_2 emission limits on the auxiliary boiler and the biogas flare will maintain the facility's synthetic minor status.

Following issuance of this PTC, the facility's PTE of SO_2 is approximately 32.5 T/yr, based on the emission estimates provided by the permittee and allowable operation for the emergency backup electrical generator.

Annual PTE for CO is 72 T/yr and 66 T/yr for NO_x. This facility's status will change to a synthetic minor (SM) source upon issuance of this PTC. The facility held an SM-80 (synthetic minor source limited to 80% or above of the threshold for each regulated air pollutant) designation with permit allowable emissions of 98 T/yr of SO_2 in PTC No. 047-00008, issued May 7, 2000, which will be replaced by this PTC.

Major source Tier I permitting requirements do not apply to this facility.

IDAPA 58.01.01.625................Visible Emissions

The proposed flare and the auxiliary boiler are subject to the State of Idaho visible emissions standard of 20% opacity.

IDAPA 58.01.01.676................Fuel Burning Equipment—Particulate Matter—Standards for New Sources

Existing process Boilers 1, 2, 3, and 4 are subject to the particulate matter grain loading standard of 0.015 gr/dscf, corrected to 3% oxygen because all are allowed to combust gas. The auxiliary boiler is also subject to this standard for both natural gas and biogas, which are both categorized as gaseous fuels. Based on the calculations submitted by the permittee, compliance with the grain loading standard has been demonstrated for Boilers 2, 3, and 5 using the "F-factor" calculation method contained in 40 CFR 60, Appendix A, Method 19. It is assumed that process Boilers 1 and 4 also comply with the grain loading standard for fuel burning equipment combusting natural gas.

Calculations provided by the permittee demonstrate that Boilers 2 and 3 comply with the grain loading standard of 0.050 gr/dscf, corrected to 3% oxygen, for liquid fuel (distillate fuel oil) by also using the "F-factor" calculation method.

IDAPA 58.01.01.728............Rules for Sulfur Content of Fuels—Distillate Fuel Oil

Boilers 2 and 3 are subject to the following limitations on sulfur content in distillate fuels:

> "No person shall sell, distribute, use or make available for use, any distillate fuel oil containing more than the following percentages of sulfur:
>
> **01. ASTM Grade 1.** ASTM Grade 1 fuel oil - 0.3% by weight.
>
> **02. ASTM Grade 2.** ASTM Grade 2 fuel oil - 0.5% by weight."

The permittee has requested an enforceable limit of 0.05% by weight of sulfur in the distillate fuel.

IDAPA 58.01.01.775-776...............Rules for the Control of Odors

The facility is subject to the general restrictions for the control of odors from the Gooding facility.

IDAPA 58.01.01.786...............Rules for Control of Incinerators—Emissions Limits

The flare is subject to the particulate matter emission standard for incineration. An "incinerator" is defined by IDAPA 58.01.01.006.51, which reads, in part:

> "For purposes of these rules, the destruction of any combustible liquid or gaseous material by burning in a flare stack shall be considered incineration."

The emission standard specified by IDAPA 58.01.01.786 requires that particulate matter emissions from the incinerator remain below 0.2 pounds per 100 pounds of refuse burned.

The permittee estimated particulate matter emissions to be 0.016 pounds per 100 pounds of refuse (methane from biogas in this case). Compliance was demonstrated by calculation of PM emissions.

40 CFR 60—Subpart Dc.............Standards of Performance for Small Industrial –Commercial – *Institutional Steam Generating Units*

See Appendix D to review EPA Region 10's July 13, 2005, formal NSPS Subpart Dc determination on the permittee's alternative monitoring, recordkeeping, and reporting requirements for Boilers 1 through 5.

The existing Process Boilers 2, 3, and 4 are subject to 40 CFR 60.40 et. al. due to construction dates and rated heat input capacities of each boiler. The installation date of Boiler 1 pre-dates NSPS—Subpart Dc applicability, and this emissions unit is not subject to any NSPS requirements.

Boiler 4 is permitted to combust natural gas only. Boilers 2 and 3 are permitted to combust either natural gas or low sulfur distillate fuel oil. Initial notification requirements apply to each of these boilers as an affected facility under 40 CFR 60—Subpart Dc, although initial notification should have been provided to EPA when the emissions units were originally constructed. This condition is retained to maintain the integrity of the May 7, 2000 PTC.

The permittee obtained a formal written determination of the monitoring and recordkeeping requirements for all five boilers at the Gooding facility, and the determination is contained in Appendix D of this memorandum.

NSPS Subpart Dc monitoring and recordkeeping applies to the process boilers as follows:

- Boiler 1 is not subject to NSPS Subpart Dc because it was constructed prior to the applicability date of the NSPS. Boiler 1 is fired exclusively by natural gas. Monitoring and recordkeeping established by the State of Idaho will follow the guidelines set for the rest of the boilers.
- Boilers 2 and 3 operate on natural gas, or low sulfur distillate fuel oil having a sulfur content limit of 0.05 wt%. EPA approved monthly recordkeeping of both natural gas and distillate fuel oil.

Boilers 2 and 3 will each have an individual fuel oil usage meter. Monthly monitoring and recordkeeping frequency is required.

- Boiler 4 operates on natural gas exclusively and EPA has approved monthly recordkeeping of fuel usage.

Boilers 2, 3, and 4 are approved to share a single natural gas usage meter and the fuel usage will be monitored and recorded on a monthly basis. If more than one boiler is fired on natural gas during the monthly period, the permittee may prorate natural gas usage by dividing the heat input capacity of each boiler by the aggregated design heat input capacities of the boilers operated during that monthly period.

- Boiler 5 is fired primarily on biogas generated by the anaerobic digester, and by natural gas as a backup fuel. Natural gas is also combusted at the same time as the biogas. EPA Region 10 denied approval of an alternative monitoring and recordkeeping of fuel consumption by Boiler 5 pending a determination that the biogas contains less than 0.5 wt % of sulfur with little variability in sulfur content. Monitoring and recordkeeping is required to be conducted daily in accordance with 40 CFR 60.58c(g).

Boilers 2 and 3 are subject to the sulfur dioxide emission standard of 0.5 lb/MMBtu; or, alternatively, a limit of 0.5 weight percent sulfur in the fuel oil combusted. The permittee may comply with either form of the sulfur standard. Monitoring and recordkeeping requirements to demonstrate compliance with the limitation on sulfur content in fuel limit is more easily established by the permittee and is done so by obtaining the written certification from the fuel supplier.

Boilers 4 and 5 have rated heat input capacities of less than 30 MMBtu/hr and are operated on natural gas and biogas, respectively. These boilers are not subject to the sulfur dioxide and particulate matter emission standards specified by 40 CFR 60.42c and 40 CFR 60.43c, respectively. Boilers 2 and 3 operate on either natural gas or distillate fuel oil and have rated heat input capacities of less than 30 MMBtu/hr. Therefore, in accordance with 40 CFR 60.43c(c), these emissions units are not subject to the particulate matter emission standards specified in 40 CFR 60.43c.

5.5 Permit Conditions Review

This section describes only those permit conditions that have been revised, modified, or deleted as a result of this permit action.

Permit Conditions 2.3 through 2.16 are new permit conditions that address the operations of the biogas flare and the auxiliary boiler.

Permit Condition 2.3 reads:

2.3 ***<u>Emissions Limits</u>***

2.3.1 The total SO_2 emissions from the auxiliary boiler stack and the biogas flare shall not exceed 30.1tons per any consecutive 12-month period.

2.3.2 H_2S Emissions Limits

- *Emissions of H_2S from the biogas flare shall not exceed 8.66 lb/day.*
- *Emissions of H_2S from the biogas flare shall not exceed 1.58T/yr.*
- *Emissions of H_2S from the auxiliary boiler shall not exceed 1.73 lb/day while combusting biogas.*
- *Emissions of H_2S from the auxiliary boiler shall not exceed 0.32 T/yr while combusting biogas.*

Permit Condition 2.3 establishes enforceable SO_2 and H_2S emission limits for the biogas flare and the auxiliary boiler. The H_2S emissions limits in Permit Condition 2.3.2 are required to comply with IDAPA 58.01.01.210.

Permit Condition 2.4 reads:

2.4 ***Opacity Limit***

Emissions from the biogas flare or from the auxiliary boiler stack, or any other stack, vent, or functionally equivalent opening associated with the flare or auxiliary boiler, shall not exceed 20% opacity for a period or periods aggregating more than three minutes in any 60-minute period as required by IDAPA 58.01.01.625. Opacity shall be determined by the procedures contained in IDAPA58.01.01.625.

Permit Condition 2.4 establishes the opacity standard for the biogas flare and the auxiliary boiler. No monitoring and recordkeeping requirements have been included in the PTC to demonstrate compliance with this emissions limit.

Permit Condition 2.5 reads:

2.5 ***Boiler Grain Loading Limit***

The permittee shall not discharge to the atmosphere from the auxiliary boiler stack, PM in excess of 0.015 gr/dscf of effluent gas corrected to 3% oxygen by volume for gas.

This permit condition establishes the grain loading standard for fuel combustion equipment that is fired on gaseous fuels—biogas and natural gas. No additional testing, monitoring, or record keeping is specified in the permit to demonstrate compliance with this emission standard.

Permit Condition 2.6 reads:

2.6 ***Biogas Flare Particulate Matter Emissions Limit***

Particulate emissions from the biogas flare shall not exceed 0.2 pounds per 100 pounds of biogas burned.

The flare is defined as an incinerator and is subject to the PM emission standard for incinerators. No additional testing, monitoring, or record keeping is specified in the permit to demonstrate compliance with this emission standard.

Permit Condition 2.7 reads:

2.7 ***Rules for the Control of Odors***

No person shall allow, suffer, cause or permit the emission of odorous gases, liquids, or solids into the atmosphere in such quantities as to cause air pollution.

This is the standard requirement for control of odors. No additional monitoring and recordkeeping is required by this permit.

Permit Condition 2.8 reads:

2.8 Requirements to Install Flare and to Combust Digester Emissions

The permittee shall install, calibrate, maintain, and operate a flare for combustion of the biogas emitted from the anaerobic digester. All emissions of air pollutants from the anaerobic digester shall be combusted in either the auxiliary boiler or the flare.

The permittee is required to construct the biogas-fired flare and to either incinerate the biogas generated by the anaerobic digester in the flare or to combust it in the auxiliary boiler. This results in the appropriate levels of H_2S destruction.

Permit Condition 2.8 reads:

2.9 Pilot Flame and Alarm

The flare shall be operated with a pilot flame present during the operation of the digester. In the event of a flame failure, the permittee shall follow a standard operating procedure to reinitiate the pilot flame as expeditiously as practicable.

Within 60 days of issuance of this permit, the permittee shall install a thermocouple or similar device that detects the presence of a flame in the biogas flare. This device shall be periodically calibrated and operated at all times when the flare is operating. In addition, the permittee shall install an alarm that notifies the operator in the case of a flameout within 60 days of issuance of this permit. The permittee shall follow the excess emissions procedures in IDAPA 58.01.01.130-136 in the event of an excess emissions event caused by the biogas flare.

The presence of a pilot flame during periods of anaerobic digester operation ensures the backup control device is on-line for the incineration of the biogas. The flare is to be operated while the auxiliary boiler is off-line or exclusively combusting natural gas. The pilot flame monitoring device and alarm help ensure the proper incineration of the biogas in the flare.

Permit Condition 2.10 reads:

2.10 Concurrent Operation of the Flare and the Auxiliary Boiler

The flare and the auxiliary boiler shall not operate concurrently while combusting biogas.

The ambient impact analysis presented by the permittee did not consider concurrent operation of the biogas flare and the auxiliary boiler while both are combusting biogas. Biogas combustion capabilities for operation of the individual units were used in the analysis. The permittee intends to operate only one unit on biogas at any time and the fuel delivery system for the emissions units is capable of supplying biogas to either the flare or the boiler.

Permit Condition 2.11 reads:

2.11 NSPS-Subpart Dc Applicability Notification, Monitoring, Reporting and Recordkeeping Requirements (Auxiliary Boiler 5)

In accordance with 40 CFR 60.48c(a), the permittee shall submit notification of the date of construction or reconstruction, anticipated startup, and actual startup as required by 40 CFR 60.7 for the affected emissions unit.

The notification shall include the following:

- *the design heat input capacity of the affected facility,*
- *fuels to be combusted in the affected facility,*
- *the annual capacity factor at which the permittee anticipates operating the affected facility based on all fuels fired and based on each fuel fired.*

  The monitoring and recordkeeping of fuels combusted in Boiler 5 shall comply with 40 CFR 60.48c(g):

- *The owner or operator of each affected facility shall record and maintain records of the amounts of each fuel combusted during each day, unless alternative monitoring, recordkeeping, and reporting is formally approved by EPA Region 10.*
- *The permittee shall maintain written documentation of any EPA-approved monitoring, recordkeeping, and reporting requirements with this permit.*

The auxiliary boiler is not subject to any specific PM or SO_2 emissions standard. Permit Condition 2.11 includes the generic monitoring, recordkeeping and reporting requirements for a gas-fired boiler. Alternative monitoring, recordkeeping and reporting requirements may apply in the future, pending on-going sulfur content analysis of the biogas, an additional petition to EPA Region 10 by the permittee, and a formal determination and approval of alternative monitoring and recordkeeping requirements.

Permit Condition 2.12 reads:

2.12 <u>Biogas Flow and H_2S Concentrations Monitoring</u>

Unless an alternative monitoring and recordkeeping method is approved by DEQ, the permittee shall comply with the following requirements:

For the hydrogen sulfide analyzer and the totalizing gas flow rate analyzer upstream of the auxiliary boiler 5 and the biogas flare, the permittee shall install, calibrate, maintain, operate, and record parameters in accordance with the O&M manual and the requirements listed below:

<u>Biogas H_2S Concentration</u>

The permittee shall perform the following to determine the quantity of H_2S produced by the anaerobic digester:

- *Calibration of the hydrogen sulfide analyzer shall be performed and recorded semi-annually.*
- *An H_2S sample shall be taken and analyzed by the hydrogen sulfide analyzer, and the H_2S concentration results recorded, at least once per week. If additional H_2S samples are taken, those shall also be recorded.*

<u>Biogas Generation</u>

The permittee shall perform the following to determine the quantity of biogas produced by the anaerobic digester:

- *Once per month, the total gas flow shall be recorded.*

H_2S and SO_2 Emission Estimates

The permittee shall estimate H_2S and SO_2 emissions according to the following methods:

- *The monthly SO_2 emissions and H_2S emissions from the flare and auxiliary boiler shall be calculated using the average H_2S concentration readings of all H_2S samples taken for each month, and the corresponding monthly biogas flow. The calculations shall be conducted using the same method as in the permit application, including a molar conversion of H_2S to SO_2, a 90% H_2S control efficiency and 90% conversion of H_2S to SO_2 for the flare; and, a 98% H_2S control efficiency, and a 100% conversion of H_2S to SO_2 emissions for the auxiliary boiler.*
- *Monthly SO_2 emissions shall be used to determine rolling 12-month total SO_2 emissions.*
- *Monthly H_2S emissions shall be used to determine rolling 12-month H_2S emissions.*

This permit condition requires the monitoring of the quantity of biogas and H_2S generated by the anaerobic digester. Monitoring of the H_2S concentration is required at least weekly. The total quantity of biogas generated is required to be monitored and recorded monthly.

The H_2S and SO_2 emissions from the biogas flare and the auxiliary boiler are calculated based on the monthly totals of biogas generated and the monthly average of weekly, or more frequent, biogas H_2S concentration readings from a H_2S analyzer. Monthly H_2S emission estimates that support compliance with the annual H_2S emissions limits have been included in the permit in lieu of daily estimates because monitoring and recordkeeping of the H_2S concentration is allowed to be conducted on a weekly basis, and the quantity of biogas generation is monitored and recorded on a monthly basis.

Permit Condition 2.13 reads:

2.13 Operations and Maintenance Manual

Within 60 days of start-up of the anaerobic digester, the permittee shall develop an operations and maintenance (O&M) manual which describes the procedures that will be followed to maintain good working order and assure operation as efficiently as practical for the H_2S monitor and the pilot flame detector. The procedures and specifications described in the O&M manual shall address, at a minimum, the following topics:

H_2S Monitor

- *Standard operational procedure for H_2S sampling*
- *Frequency and method of calibration*
- *Operational maintenance*
- *Procedures for upset/breakdown conditions and for correcting equipment malfunctions*

Pilot Flame Detector

- *Method of ensuring continuous operation*
- *Operational maintenance*

Within 60 days of start-up of the digester, a copy of the O&M manual shall be submitted to the DEQ Twin Falls Regional Office at the following address:

Air Quality Permit Compliance
Department of Environmental Quality
Twin Falls Regional Office
601 Pole Line Road, Suite 2
Twin Falls, Idaho 83301
Phone: (208) 736-2190 *Fax: (208) 736-2194*

The permittee is required to develop an O&M manual that addresses proper and efficient operation of the H_2S monitoring device and pilot flame detection system. Upset and breakdown conditions are also to be addressed in the manual.

Permit Condition 2.14 reads:

2.14 Recordkeeping Requirement

A compilation of the most recent two years of records shall be kept onsite and shall be made available to DEQ representatives upon request.

This is a standard record retention requirement.

Permit No. P-040404 contains a separate section to regulate the process boilers, listed under SECTION 3—PROCESS BOILERS.

Permit Condition 1.1.2, in PTC 047-00008, issued May 7, 2000 contained SO_2 emission limits for the four existing process boilers, and read:

1.1.2 Sulfur Dioxide Emissions

Sulfur dioxide (SO_2) emissions emanating from any boiler stack shall not exceed 0.5 lb/MMBtu heat input as required in 40 CFR 60.42c, nor shall sulfur dioxide (SO_2) emissions resulting from the combustion of #2 fuel oil in the facility boilers exceed 98T/yr.

This permit condition was revised in PTC No. P-040404 as follows:

3.3.2 NSPS—Subpart Dc Sulfur Dioxide Emission Standard

Sulfur dioxide (SO_2) emissions from any oil-fired process boiler stack shall not exceed 0.5 lb/MMBtu heat input, as required in 40 CFR 60.42.c(d), or as an alternative, the sulfur content in any oil combusted in any oil-fired process boiler shall not be greater than 0.5 wt%.

3.3.3 Annual Sulfur Dioxide Emission Limit

Aggregated annual emissions of SO_2 from Boilers 2 and 3 shall not exceed 1.4 T/yr while combusting distillate fuel oil.

Only Boilers 2 and 3 are permitted to combust distillate fuel oil. The permittee requested a reduction in permit allowable SO_2 emissions for the process boilers from 98 T/yr to 1.4 T/yr. Permit Condition 3.3.1 in PTC No. P-040404 was revised to include the alternative sulfur standard for fuel oil of 0.5 wt % in 40 CFR 60—Subpart Dc.

Permit Condition No. 2.1 in PTC No. 047-00008, issued May 7, 2000, originally read:

2.1 *Fuel Types*

The facility boilers shall burn natural gas and #2 fuel oil exclusively.

Permit Condition No. 3.5 of PTC No. P-040404 replaces Permit Condition 2.1 listed above and reads:

3.5 ***Allowable Fuel Types***

- *Boilers 1 and 4*

  Boilers 1 and 4 shall combust natural gas exclusively.

- *Boilers 2 and 3*

  Boilers 2 and 3 shall combust either natural gas or low sulfur distillate fuel oil.

The revised operating requirement condition specifies the allowable fuel types for each process boiler.

Permit Condition No. 2.2 in PTC No. 047-00008, issued May 7, 2000, originally read:

2.2 *Facility-wide #2 Fuel Oil Combustion Limit*

The maximum amount of #2 fuel oil combusted in the facility boilers shall not exceed two million seven hundred sixty thousand five hundred sixty-three gallons per year (2,760,563 gal/yr).

Permit Condition No. 3.6 of PTC No. P-040404 replaces Permit Condition 2.2 listed above, and reads:

3.6 ***Distillate Fuel Oil Throughput Limit***

The total throughput of low sulfur distillate fuel oil combusted either individually or aggregated in Boilers 2 and 3 shall not exceed 387,258 gallons per any consecutive 12-month period.

Low sulfur content distillate fuel oil will be limited to 387,258 gallons per year, on a consecutive 12-month basis. The fuel throughput limitation is applied to the boilers in aggregate rather than an individual basis.

Permit Condition No. 2.3 in PTC No. 047-00008, issued May 7, 2000, originally read:

2.3 *Fuel Sulfur Content*

Total sulfur content of the #2 fuel oil shall not exceed five-tenths percent (0.5%) by weight as required in 40 CFR 60.42c and IDAPA 16.01.01.728.02.

Permit Condition No. 3.7 of PTC No. P-040404 replaces Permit Condition 2.3 listed above, and reads:

3.7 ***Distillate Fuel Oil Sulfur Content Limit***

The sulfur content of any distillate fuel oil combusted in Boilers 2 and 3 shall not exceed 0.05 wt%.

The sulfur content in the distillate fuel has been limited to 0.05 wt %, as requested by the permittee. This limitation is more stringent than the sulfur content limitations specified by IDAPA 58.01.01.728.01 and 728.02 for distillate fuel oil. Therefore, the permit reflects the more stringent sulfur limitation as an operating requirement.

Permit Condition No. 3.1 in PTC No. 047-00008, issued May 7, 2000, originally read:

3.1 *#2 Fuel Oil Combustion Monitoring*

The permittee shall monitor and record, monthly and annually, based on a calendar year, the amount of #2 fuel oil combusted. The amount shall be recorded as gallons per month (gal/mo) and gallons per year (gal/yr) to demonstrate compliance with Section 2.2 of this permit and shall be recorded in a log kept at the facility for the most recent two (2) year period. The log shall be made available to Department representatives upon request.

Permit Condition No. 3.9 of PTC No. P-040404 replaces Permit Condition 3.1 listed above, and reads:

3.9 ***Distillate Fuel Oil Combustion Monitoring***

The permittee shall monitor and record the throughput of distillate fuel oil combusted in Boilers 2 and 3 monthly and annually, expressed as gallons per month (gal/mo) and gallons per year (gal/yr), to demonstrate compliance with Permit Condition 3.6. Annual throughput shall be determined by summing each monthly throughput over the previous consecutive 12-month period...

Permit Condition 3.9 of PTC No. P-040404 is essentially the same as Permit Condition 3.1 of the original PTC, and is used to establish compliance with the fuel throughput limitation in Permit Condition 3.6 in PTC No. P-040404. The annual monitoring period was changed from a calendar year to a one-year period consisting of any consecutive 12-month period.

Permit Condition No. 3.2 in PTC No. 047-00008, issued May 7, 2000, originally read:

3.2 *#2 Fuel Oil Sulfur Content Monitoring*

The #2 fuel oil shall be monitored by the permittee, or verified by the supplier, to determine the maximum content by weight each time the #2 fuel oil is introduced into the fuel storage tank(s) or equivalent. This information shall be recorded in a log kept at the facility for the most recent two (2) year period. The log shall be made available to Department representatives upon request.

Permit Condition No. 3.10 of PTC No. P-040404 replaces Permit Condition 3.2 listed above, and reads:

3.10 ***NSPS-Subpart Dc Distillate Fuel Oil Sulfur Content Monitoring, Recordkeeping and Reporting Requirements (Boilers 2 and 3)***

The permittee shall comply with the following requirements for Boilers 2 and 3, in accordance with 40 CFR 60.42c(h):

- *The permittee shall demonstrate compliance with the fuel oil sulfur content limits specified in Permit Condition 3.7 and 40 CFR 60.42c(d) by complying with 40 CFR 60.48c(d), CFR 60.48c(e), and 40 CFR 60.48c(f).*

- *Records of each fuel oil sulfur content certification shall remain onsite for the most recent two-year period in accordance with 40 CFR 60.48c(i),and shall be made available to DEQ representatives upon request.*

- *Semi-annual reports shall be submitted to EPA Region 10 in accordance with 40 CFR 60.48c(j).*

Boilers 2 and 3 are subject to NSPS—Subpart Dc and Permit Condition 3.10 in the current PTC reflects the NSPS requirements for monitoring and recordkeeping as specified by EPA Region 10's formal alternative monitoring and recordkeeping approval letter, dated July 13, 2005.

Permit Condition No. 4.1 in PTC No. 047-00008, issued May 7, 2000, originally read:

4.1 <u>*Certification of Documents*</u>

All documents, including but not limited to, records, supporting information, or monitoring data submitted to the Department shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the documents are true, accurate, and complete.

General Provision No. 8 of PTC No. P-040404 replaces Permit Condition 4.1 listed above, and reads:

8. In accordance with IDAPA 58.01.01.123, all documents submitted to DEQ, including, but not limited to, records, monitoring data, supporting information, requests for confidential treatment, testing reports, or compliance certification shall contain a certification by a responsible official. The certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document(s) are true, accurate, and complete.

Permit Condition No. 5.1 in PTC No. 047-00008, issued May 7, 2000, originally read:

5.1 The Permittee shall comply with the provisions of IDAPA 16.01.01.600-616 to protect public health and welfare from air pollutants resulting from open burning.

Permit Condition No. 3.8 of PTC No. P-040404 replaces Permit Condition 4.1 listed above, and reads:

3.8 <u>***Rules for the Control of Open Burning***</u>

The permittee shall comply with the provisions of IDAPA 58.01.01.600-617 to protect public health and welfare from air pollutants resulting from open burning.

This permit condition was included under the operating requirements section of PTC No. P-040404. The regulatory citation has changed to reflect the current version of the *Rules for Control of Air Pollution in Idaho*, which, in part, were adopted in the *Rules* on March 21, 2003.

All other permit conditions remain unchanged.

6. PERMIT FEES

The permittee submitted a $1000.00 PTC application fee on June 24, 2004. The PTC processing fee was estimated using the worst-case potential emissions of the proposed biogas flare and the auxiliary boiler. Annual emission reductions were estimated for the requested reduction in backup distillate fuel oil throughput and sulfur content. A processing fee of $1000.00 is required for a new source or modification to an existing source with an emissions increase of less than one (1) ton per year. Refer to Table 5.8 to review the emissions rates used to establish the processing fee. The processing fee was received at DEQs Twin Falls Regional Office on September 8, 2005.

Glanbia Foods, in Gooding, is a synthetic minor facility for the purposes of the Tier I major source permitting. The facility is not subject to major Tier I source registration fee requirements and this project does not affect those requirements.

Table 5.8 PTC PROCESSING FEE TABLE

Emissions Inventory			
Pollutant	**Annual Emissions Increase (T/yr)**	**Annual Emissions Reduction (T/yr)**	**Annual Emissions Change (T/yr)**
NO_X	12.2	23.75	-11.6
SO_2	30.1	96.6	-66.5
CO	19.0	5.93	+13.1
PM_{10}	0.9	02.37	-1.5
VOC	3.2	0.66	+2.6
TAPS/HAPS	3.2	0.013	+2.6
Total:	67.7	129.3	**-61.6**
Fee Due	**$ 1,000.00**		

7. PERMIT REVIEW

7.1 Regional Review of Draft Permit

A draft PTC package was sent to the Twin Falls Regional Office on August 29, 2005.

7.2 Facility Review of Draft Permit

The facility declined to review the draft permit.

7.3 Public Comment

An opportunity for public comment period on the PTC application was provided from April 5, 2005 to May 2, 2005, in accordance with IDAPA 58.01.01.209.01.c. During this time, there were no comments on the application and no requests for a public comment period on DEQ's proposed action.

8. RECOMMENDATION

Based on review of application materials, and all applicable state and federal rules and regulations, staff recommend that Glanbia Foods, Inc., be issued final PTC No. P-040404 for the construction and operation of a biogas-fired flare, a biogas/natural gas-fired auxiliary boiler, and revised emission and operating limitations for the four existing process boilers. No public comment period is recommended, no entity has requested a comment period, and the project does not involve PSD requirements.

DM/sd Permit No. P-040404

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Appendix A

AIRS Information

P-040404

AIRS/AFS[a] FACILITY-WIDE CLASSIFICATION[b] DATA ENTRY FORM

Facility Name: Glanbia Foods, Inc. (P-040404)
Facility Location: Gooding
AIRS Number: 047-00008

AIR PROGRAM POLLUTANT	SIP	PSD	NSPS (Part 60)	NESHAP (Part 61)	MACT (Part 63)	SM80	TITLE V	AREA CLASSIFICATION A-Attainment U-Unclassified N- Nonattainment
SO_2	SM		SM				SM	U
NO_x	B							U
CO	B							U
PM_{10}	B							U
PT (Particulate)	B							Not Applicable
VOC	B							U
THAP (Total HAPs)	B							U
			APPLICABLE SUBPART					
			Dc					

[a] Aerometric Information Retrieval System (AIRS) Facility Subsystem (AFS)

[b] AIRS/AFS Classification Codes:

- A = Actual or potential emissions of a pollutant are above the applicable major source threshold. For HAPs only, class "A" is applied to each pollutant which is at or above the 10 T/yr threshold, or each pollutant that is below the 10 T/yr threshold, but contributes to a plant total in excess of 25 T/yr of all HAPs.
- SM = Potential emissions fall below applicable major source thresholds if and only if the source complies with federally enforceable regulations or limitations.
- B = Actual and potential emissions below all applicable major source thresholds.
- C = Class is unknown.
- ND = Major source thresholds are not defined (e.g., radionuclides).

Appendix B

Emissions Inventory

P-040404

Emission Estimate Summary

Preliminary Annual Emissions Estimates
Criteria Pollutants

Stack Name (MM Btu/hr)	Stack ID	Emission Rate (ton/year)						
		PM	PM10	NOx	SO2	CO	VOC	Lead
Boiler 1 (29.35)	BOILER1	0.92	0.92	12.17	0.07	10.22	0.67	6.09E-05
Boiler 2 (Dual 25.1)-Nat Gas	BOILER2	0.69	0.69	9.12	0.05	7.66	0.50	4.56E-05
Boiler 3 (Dual 25.1)-Nat Gas	BOILER3	0.69	0.69	9.12	0.05	7.66	0.50	4.56E-05
Boiler 2 (Diesel)	BOIL2D	0.19	0.19	1.94	0.69	0.48	0.05	1.22E-04
Boiler 3 (Diesel)	BOIL3D	0.19	0.19	1.94	0.69	0.48	0.05	1.22E-04
Boiler 4 (25.1)	BOILER4	0.79	0.79	10.41	0.06	8.74	0.57	5.20E-05
Boiler 5 (Biogas)	BOILER5	0.73	0.73	8.65	30.11	11.00	1.17	3.47E-05
Flare	FLARE	0.37	0.37	3.50		19.04	3.24	-
Dryer	DRYER1	0.29	0.29	3.81	0.02	3.20	0.21	1.91E-05
Generator	GEN1	0.06	0.06	1.82	0.29	0.48	0.05	5.13E-06
Heater 1 (1.5)	HEAT1	0.05	0.05	0.62	0.004	0.52	0.03	3.11E-06
Heater 2 (5.89)	HEAT2	0.19	0.19	2.44	0.01	2.05	0.13	1.22E-05
Heater 3 (1.374)	HEAT3	0.04	0.04	0.57	0.003	0.48	0.03	2.85E-06
Total		5.22	5.22	66.12	32.06	72.04	7.23	5.25E-04

Preliminary Maximum Hourly Emissions Estimates
Criteria Pollutants

Stack Name	Stack ID	Emission Rate (lb/hr)						
		PM	PM10	NOx	SO2	CO	VOC	Lead
Boiler 1 (29.35)	BOILER1	0.21	0.21	2.78	0.02	2.33	0.15	1.39E-05
Boiler 2 (Dual 25.1)*	BOILER2	0.36	0.36	3.59	1.27	2.00	0.13	2.26E-04
Boiler 3 (Dual 25.1)*	BOILER3	0.36	0.36	3.59	1.27	2.00	0.13	2.26E-04
Boiler 2 (Diesel)	BOIL2D	0.36	0.36	3.59	1.27	0.90	0.10	2.26E-04
Boiler 3 (Diesel)	BOIL3D	0.36	0.36	3.59	1.27	0.90	0.10	2.26E-04
Boiler 4 (25.1)	BOILER4	0.18	0.18	2.38	0.014	2.00	0.13	1.19E-05
Boiler 5 (Biogas)	BOILER5	0.17	0.17	1.98	6.87	2.51	0.27	7.92E-06
Flare	FLARE	0.08	0.08	0.80		4.35	0.74	-
Dryer	DRYER1	0.07	0.07	0.87	0.005	0.73	0.05	4.35E-06
Generator	GEN1	0.57	0.57	1.82	2.88	0.48	0.05	5.13E-05
Heater 1 (1.5)	HEAT1	0.01	0.01	0.14	0.001	0.12	0.01	7.10E-07
Heater 2 (5.89)	HEAT2	0.04	0.04	0.56	0.003	0.47	0.03	2.79E-06
Heater 3 (1.374)	HEAT3	0.01	0.01	0.13	0.001	0.11	0.01	6.50E-07
Total		2.78	2.78	25.80	14.88	18.89	1.90	9.97E-04

Note: Note that boiler 5 and the flare do not operate at the same time. Worse case SO_2 emission estimates for boiler 5 and the flare were compared and the boiler 5 emission estimates are included for the facility-wide model.

Toxics

Toxic Air Pollutants[3]	Boiler 2 (Dual 25.1)*	Boiler 3 (Dual 25.1)*	Boiler 5 (Biogas)	Flare	Total	IDAPA 58.01.01.585/586 - EL (lb/hr)	Compare to EL
3-Methylchloranthrene	-	-	2.85E-08	-	2.85E-08	2.50E-06	Below
Benzene	3.84E-05	3.84E-05	1.15E-04	2.87E-03	3.07E-03	8.00E-04	**Exceeds**
Benzo(a)pyrene	-	-	1.90E-08	-	1.90E-08	2.00E-06	Below
Ethylbenzene	1.14E-05	1.14E-05	-	-	2.28E-05	2.90E+01	Below
Formaldehyde	-	-	1.19E-03	2.11E-02	2.23E-02	5.10E-04	**Exceeds**
Hexane	-	-	2.85E-02	-	2.85E-02	1.20E+01	Below
Methyl chloroform	4.23E-05	4.23E-05	-	-	8.46E-05	1.27E+02	Below
Naphthalene	2.03E-04	2.03E-04	9.67E-06	-	4.15E-04	3.33E+00	Below
Pentane	-	-	4.12E-02	-	4.12E-02	1.18E+02	Below
POM	5.92E-04	5.92E-04	-	-	1.18E-03	2.00E-06	**Exceeds**
Toluene	1.11E-03	1.11E-03	5.39E-05	-	2.28E-03	2.50E+01	Below
o-Xylenes	1.95E-05	1.95E-05	-	-	3.91E-05	2.90E+01	Below
Total PAH	-	-	7.23E-06	2.53E-04	2.60E-04	2.00E-06	**Exceeds**
Acetaldehyde	-	-	-	-	0.00E+00	3.00E-03	Below
Acrolein	-	-	-	-	0.00E+00	1.70E-02	Below
Ammonia	-	-	5.78E-02	5.78E-02	1.16E-01	1.20E+00	Below
Hydrogen Sulfide	-	-	7.22E-02	3.61E-01	4.33E-01	9.33E-01	Below
Toxic Air Pollutants-Metals[4]						IDAPA 58.01.01.585/586 - EL (lb/hr)	Compare to EL
Arsenic	1.00E-04	1.00E-04	3.17E-06	-	2.04E-04	1.50E-06	**Exceeds**
Barium	-	-	6.97E-05	-	6.97E-05	3.30E-02	Below
Beryllium	7.53E-05	7.53E-05	1.90E-07	-	1.51E-04	2.80E-05	**Exceeds**
Cadmium	7.53E-05	7.53E-05	1.74E-05	-	1.68E-04	3.70E-06	**Exceeds**
Chromium	7.53E-05	7.53E-05	2.22E-05	-	1.73E-04	3.30E-02	Below
Cobalt	-	-	1.33E-06	-	1.33E-06	3.30E-03	Below
Copper	1.51E-04	1.51E-04	1.35E-05	-	3.15E-04	1.30E-02	Below
Manganese	1.51E-04	1.51E-04	6.02E-06	-	3.07E-04	6.70E-02	Below
Mercury	7.53E-05	7.53E-05	4.12E-06	-	1.55E-04	1.00E-03	Below
Molybdenum	-	-	1.74E-05	-	1.74E-05	3.33E-01	Below
Nickel	7.53E-05	7.53E-05	3.33E-05	-	1.84E-04	2.75E-05	**Exceeds**
Selenium	3.77E-04	3.77E-04	3.80E-07	-	7.53E-04	1.30E-02	Below
Vanadium	-	-	3.65E-05	-	3.65E-05	3.00E-03	Below
Zinc	1.00E-04	1.00E-04	4.60E-04	-	6.60E-04	3.33E-01	Below

Glanbia Gooding Biogas Flare

Heat Input (MMBtu/hr)	**11.75**
Manufacturer	**Biothane**
Fuel Type	**Biogas**
Fuel Heat Value (Btu/scf)	**650**
Max Biogas Production (scf/day) (based on highest expected sulfate concentration)	**433,823**
Max Fuel Use (scf/min)	**301**
Secondary Fuel Type	**Natural Gas**
Natural Gas Heat Value (Btu/scf) (for emission factor conversion)	**1,056**
Operation (hrs/yr)	**8,760**
Hydrogen Sulfide (H_2S) Biogas Concentration (ppmv)	**2,297**
H_2S Biogas Concentration (mg/m^3)	**3,204**
H_2S Mass Feedrate (lb/hr)	**3.6**
Assumed H_2S Conversion for SO_2 Emissions	**90%**

				Uncontrolled Potential to Emit		
Criteria Pollutant	**CAS No.**	**Emission Factor** [1]		**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM) [2]		7.6	lb MM cf NG	0.085	741	0.37
Nitrogen Oxides (NOx)		0.068	lb/MM Btu	0.799	6,999	3.50
Sulfur Dioxide (SO_2) [3]		H_2S / SO_2 Mass Balance		6.11	53,528	26.76
Carbon Monoxide (CO)		0.37	lb/MM Btu	4.347	38,082	19.04
VOC		0.06	lb/MM Btu	0.740	6,484	3.24

				Primary Fuel - Biogas Controlled Potential to Emit				
Toxic Air Pollutants - H_2S	**CAS No.**	**Emission Factor** [4] **(% Destruction)**		**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**	**IDAPA 58.01.01.585/586 - EL (lb/hr)**	**PTE Emission Rate vs. EL**
Hydrogen sulfide	7783-06-4	90%		3.61E-01	3.16E+03	1.58E+00	9.33E-01	Below

				Primary Fuel - Biogas [4] Uncontrolled Potential to Emit				
Toxic Air Pollutants - Others [5]	**CAS No.**	**Digester Gas Emission Factor (lb/10^6 scf)**	**Natural Gas Emission Factor (lb/10^6 scf)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**	**IDAPA 58.01.01.585/586 - EL (lb/hr)**	**PTE Emission Rate vs. EL**
Ammonia	7664-41-7	3.20E+00		5.78E-02	5.07E+02	2.53E-01	1.20E+00	Below
Benzene	71-43-2	1.59E-01	1.59E-01	2.87E-03	2.52E+01	1.26E-02	8.00E-04	**Exceeds**
Formaldehyde	50-00-0	1.17E+00	1.17E+00	2.11E-02	1.85E+02	9.26E-02	5.10E-04	**Exceeds**
PAHs	na	1.40E-02	1.40E-02	2.53E-04	2.22E+00	1.11E-03	9.10E-05	**Exceeds**

Notes:

[1] Criteria pollutants emission rates from AP-42, Section 13.5 (Industrial Flares) w/ exception of PM and SO_2 (see below).

[2] PM emissions based on natural gas combustion, per AP-42 Table 1.4-2, due to extreme range and concentration-based format of industrial flare PM factors

[3] SO_2 Emission factor for biogas assumes 100% conversion of H_2S to SO_2. Natural gas SO2 factor based on AP-42, Table 1.4-2.

[4] Conservatively estimated H_2S destruction based on engineering judgement and combustion properties of H_2S

[5] Emission factors from "General Instruction Book for the 2003 - 2004 Annual Emissions Reporting Program", Tables 4 and 10, South Coast Air Quality Managment District (SCAQMD).

Glanbia Gooding 400 hp Boiler (Boiler 5 - WWTF)

Boiler Heat Input (MMBtu/hr)	16.7375	2005 Cleaver Brooks
Model No.	CB700 - 400 - 30HW	
Primary Fuel Type	Biogas	
Max Biogas Production (scf/day) (based on highest expected sulfate concentration)	433,823	
Primary Fuel Heat Value (Btu/scf)	650	
Max Primary Fuel Use (10^6 scf/hr)	0.0181	
Secondary Fuel Type	Natural Gas	
Secondary Fuel Heat Value (Btu/scf)	1,050	
Max Heat Input from Biogas (MMBtu/hr)	11.7484	
Heat Input from NG (MMBtu/hr)	4.9891	
Total Heat Input (MM Btu/hr)	16.7375	
Max Secondary Fuel Use (10^6 scf/hr)	0.0047	
Operation (hrs/yr)	8,760	
Hydrogen Sulfide (H_2S) Biogas Concentration (ppmv)	2,297	
H_2S Biogas Concentration (mg/m^3)	3,204	
Max H_2S Mass Feedrate (lb/hr)	3.6	
Assumed H_2S Conversion for SO_2 Emissions	100%	

				Uncontrolled Potential to Emit							
				Primary Fuel - Biogas			Secondary Fuel - Natural Gas			Both Fuels Combined	
Criteria Pollutant	CAS No.	Emission Factor [1] (lb/MM Btu)		Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)	Emission Rate (ton/yr)
Total Particulate Matter (PM) [2]		0.010		0.117	1,029	0.5	0.050	437	0.2	0.2	0.7
Nitrogen Oxides (NOx)		0.118		1.386	12,145	6.1	0.589	5,156	2.6	2.0	8.7
Sulfur Dioxide (SO_2) [3]		0.017		6.79	59,475	29.7	0.08	743	0.4	6.9	30.1
Carbon Monoxide (CO)		0.150		1.762	15,439	7.7	0.746	6,554	3.3	2.5	11.0
VOC		0.016		0.188	1,647	0.8	0.080	699	0.3	0.3	1.2
Lead		4.73E-07		5.56E-06	4.87E-02	2.44E-05	2.36E-06	2.07E-02	1.03E-05	7.92E-06	3.47E-05

				Controlled Potential to Emit								
				Primary Fuel - Biogas			Secondary Fuel - Natural Gas			Both Fuels Combined		
Toxic Air Pollutants - H_2S	CAS No.	Emission Factor [4] (% Destruction)		Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)	IDAPA 58.01.01.585/586 - EL (lb/hr)	PTE Emission Rate vs. EL
Hydrogen sulfide	7783-06-4	98%		7.22E-02	6.33E+02	3.16E-01				7.22E-02	9.33E-01	Below

				Uncontrolled Potential to Emit								
				Primary Fuel - Biogas [5]			Secondary Fuel - Natural Gas			Both Fuels Combined		
Toxic Air Pollutants - Non-metals [7]	CAS No.	EPA AP-42 Natural Gas Emission Factor (lb/10^6 scf)	SCAQMD [6] Digester Gas Emission Factor (lb/10^6 scf)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)	IDAPA 58.01.01.585/586 - EL (lb/hr)	PTE Emission Rate vs. EL
3-Methylchloranthrene	56-49-5	1.80E-06		2.00E-08	1.75E-04	8.77E-08	8.50E-09	7.45E-05	3.72E-08	2.85E-08	2.50E-06	Below
Ammonia	7664-41-7		3.20E+00	5.78E-02	5.07E+02	2.53E-01				5.78E-02	1.20E+00	Below
Benzene	71-43-2	2.10E-03	5.80E-03	1.05E-04	9.18E-01	4.59E-04	9.92E-06	8.69E-02	4.34E-05	1.15E-04	8.00E-04	Below
Benzo(a)pyrene	50-32-8	1.20E-06		1.34E-08	1.17E-04	5.85E-08	5.67E-09	4.97E-05	2.48E-08	1.90E-08	2.00E-06	Below
Formaldehyde	50-00-0	7.50E-02	1.23E-02	8.34E-04	7.31E+00	3.65E-03	3.54E-04	3.10E+00	1.55E-03	1.19E-03	5.10E-04	Exceeds
Hexane	110-54-3	1.80E+00		2.00E-02	1.75E+02	8.77E-02	8.50E-03	7.45E+01	3.72E-02	2.85E-02	1.20E+01	Below
Naphthalene	91-20-3	6.10E-04		6.79E-06	5.95E-02	2.97E-05	2.88E-06	2.52E-02	1.26E-05	9.67E-06	3.33E+00	Below
PAHs	na		4.00E-04	7.23E-06	6.33E-02	3.17E-05				7.23E-06	9.10E-05	Below
Pentane	109-66-0	2.60E+00		2.89E-02	2.53E+02	1.27E-01	1.23E-02	1.08E+02	5.38E-02	4.12E-02	1.18E+02	Below
Toluene	108-88-3	3.40E-03		3.78E-05	3.31E-01	1.66E-04	1.61E-05	1.41E-01	7.03E-05	5.39E-05	2.50E+01	Below

				Uncontrolled Potential to Emit								
				Primary Fuel - Biogas			Secondary Fuel - Natural Gas			Both Fuels Combined		
Toxic Air Pollutants-Metals [8]	CAS Number	Emission Factor (lb/10^6 scf)		Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	Emission Rate (lb/hr)	IDAPA 58.01.01.585/586 - EL (lb/hr)	PTE Emission Rate vs. EL
Arsenic	7440-38-2	2.00E-04		2.23E-06	1.95E-02	9.75E-06	9.45E-07	8.28E-03	4.14E-06	3.17E-06	1.50E-06	Exceeds
Barium	7440-39-3	4.40E-03		4.90E-05	4.29E-01	2.14E-04	2.08E-05	1.82E-01	9.10E-05	6.97E-05	3.30E-02	Below
Beryllium	7440-41-7	1.20E-05		1.34E-07	1.17E-03	5.85E-07	5.67E-08	4.97E-04	2.48E-07	1.90E-07	2.80E-05	Below
Cadmium	7440-43-9	1.10E-03		1.22E-05	1.07E-01	5.36E-05	5.20E-06	4.55E-02	2.28E-05	1.74E-05	3.70E-06	Exceeds
Chromium	7440-47-3	1.40E-03		1.56E-05	1.36E-01	6.82E-05	6.61E-06	5.79E-02	2.90E-05	2.22E-05	3.30E-02	Below
Cobalt	7440-48-4	8.40E-05		9.35E-07	8.19E-03	4.09E-06	3.97E-07	3.48E-03	1.74E-06	1.33E-06	3.30E-03	Below
Copper	7440-50-8	8.50E-04		9.46E-06	8.28E-02	4.14E-05	4.02E-06	3.52E-02	1.76E-05	1.35E-05	1.30E-02	Below
Manganese	7439-96-5	3.80E-04		4.23E-06	3.70E-02	1.85E-05	1.79E-06	1.57E-02	7.86E-06	6.02E-06	6.70E-02	Below
Mercury	7439-97-6	2.60E-04		2.89E-06	2.53E-02	1.27E-05	1.23E-06	1.08E-02	5.38E-06	4.12E-06	1.00E-03	Below
Molybdenum	7439-98-7	1.10E-03		1.22E-05	1.07E-01	5.36E-05	5.20E-06	4.55E-02	2.28E-05	1.74E-05	3.33E-01	Below
Nickel	7440-02-0	2.10E-03		2.34E-05	2.05E-01	1.02E-04	9.92E-06	8.69E-02	4.34E-05	3.33E-05	2.75E-05	Exceeds
Selenium	7782-49-2	2.40E-05		2.67E-07	2.34E-03	1.17E-06	1.13E-07	9.93E-04	4.97E-07	3.80E-07	1.30E-02	Below
Vanadium	1314-62-1	2.30E-03		2.56E-05	2.24E-01	1.12E-04	1.09E-05	9.52E-02	4.76E-05	3.65E-05	3.00E-03	Below
Zinc	7440-66-6	2.90E-02		3.23E-04	2.83E+00	1.41E-03	1.37E-04	1.20E+00	6.00E-04	4.60E-04	3.33E-01	Below

Notes:

[1] Criteria Pollutants emission rates from manufacturer-supplied emission factors, which are more conservative (higher) than EPA AP-42 factors. Except for Lead, which is from EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-2.
Because emission factor is in lb/MM Btu heat input basis, same factor applied for biogas and natural gas combustion.

[2] PM emission factor is assumed to equal PM_{10}.

[3] SO_2 Emission factor for biogas assumes 100% conversion of H_2S to SO_2 ; manufacturer SO_2 emission factor not used

[4] Conservatively estimated H_2S destruction based on engineering judgement and combustion properties of H_2S

[5] Biogas toxic air pollutant emissions based on EPA AP-42 emission factors, times ratio of Biogas heat value to natural gas heat value, unless higher emisson factor available through SCAQMD.

[6] Emission factors from "General Instruction Book for the 2003 - 2004 Annual Emissions Reporting Program," Table 10 (Default Emission factors for Digester Gas Combustion) South Coast Air Quality Managment District (SCAQMD).

[7] Toxic Air Pollutants (EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-3).

[8] Metals from Natural Gas Combustion (EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-4).

Glanbia Gooding 400 hp Boiler (Boiler 5 - WWTF) Flow Calculations

	70/30		
Boiler Heat Input (MMBtu/hr)	**16.7375**	**25% Heat Imput**	**All Biogas**
Model No.	**CB700 - 400 - 30HW**	**CB700 - 400 - 30HW**	
Primary Fuel Type	**Biogas**	**Biogas**	**Biogas**
Primary Fuel Heat Value (Btu/scf)	**650**	**650**	**650**
Max Primary Fuel Use (10^6 scf/hr)	**0.0258**	**0.0064**	
Secondary Fuel Type	**Natural Gas**		
Secondary Fuel Heat Value (Btu/scf)	**1,056**		
Max Secondary Fuel Use (10^6 scf/hr)	**0.0158**		
Operation (hrs/yr)	**8,760**		
Max Biogas Available (10^6 scf/hr)	0.0181		0.0181
Heat input from Biogas (MMBtu/hr)	11.7494	4.184375	
Heat input from NG (MMBtu/hr)	4.9881		
Max Secondary Fuel Use (10^6 scf/hr)	0.0047		
Exhaust Comp and flow for Bio Gas	0.2005	0.0714	0.2005
Exhaust Comp and flow for NG Gas	0.0500		
Exhaust flow (10^6 scf/hr)	0.2504	0.0714	0.2005
Exhaust flow (scfm @0%O2)	4,174	1,190	3,341
Exhaust flow (scfm @ 3%O2)	4,869	1,388	3,898
Exhaust flow (acfm @ 3%O2)	8,310	2,369	6,652
Stack Exit Vel (fps)	44.08	12.57	35.29
Stack Exit Vel (mps)	13.36	3.81	10.69

Exhaust flow all NG	2,794		
	3,260		
	5,563		
	29.51		
SO2 Emission Rate lb/hr	7.47	2.66	7.47
SO2 Emission Rate tpy	32.70	11.65	32.70

1 CH4	2.007068 O2	0.0035 H2S	7.550398 N2	0.478462 CO2	=	1.478462 CO2	2.05738 H2O	0.00353 SO2	7.550398 N2	11.08977 Total exha
1 CH4	2 O2		7.52381 N2	0 CO2	=	1 CO2	2.053846 H2O		7.52381 N2	10.57766
						0.133318	0.18552	0.00032	0.680843	

Glanbia Gooding Cheese-Whey Facility (Boiler 1 burning Natural Gas)

Boiler (MMBtu/hr)	**29.35**	Continental
Model No.		
Fuel Type	**Natural Gas**	
Maximum Firing Rate (MMcf/hr)[1]	**2.78E-02**	
Maximum Operation Limit (hrs/yr)	**8,760**	
Maximum Firing Rate (MMcf/yr)	**243**	
Heat Value of Fuel (Btu/scf)	**1,056**	Value supplied by Intermountain Gas Co.

			Uncontrolled Potential to Emit		
Criteria Pollutant[2]	**CAS No.**	**Emission Factor ($lb/10^6$ scf)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[3]		7.6	0.211	1,850	0.92
Nitrogen Oxides (NOx)		100	2.78	24,340	12.17
Sulfur Oxides		0.6	0.017	146	0.07
Carbon Monoxide (CO)		84	2.33	20,446	10.22
VOC		5.5	0.153	1,339	0.67
Lead		0.0005	1.39E-05	1.22E-01	6.09E-05

Notes:

[1] Maximum Firing Rate calculated from Manufacture Boiler Rating (MMBTu/hr) and the Natural Gas heat value (Btu/scf) given by Intermountain Gas Company.

[2] Criteria Pollutants (EPA AP-42, Section 1.4 Natural Gas Consumption, Tables 1.4-1 and 1.4-2).

[3] PM emission factor is assumed to equal PM_{10}.

Glanbia Gooding Cheese-Whey Facility (Boiler 2 burning Natural Gas)

Boiler (MMBtu/hr)	**25.1**	1992 Cleaver Brooks
Model No.		
Fuel Type	**Natural Gas**	
Maximum Firing Rate (MMcf/hr)[1]	**2.38E-02**	
Maximum Operation Limit (hrs/yr)	**7,680**	8760- max hrs on diesel (see diesel spreadsheet)
Maximum Firing Rate (MMcf/yr)	**182**	
Heat Value of Fuel (Btu/scf)	**1,056**	

			Uncontrolled Potential to Emit		
Criteria Pollutant[2]	**CAS No.**	**Emission Factor ($lb/10^6$ scf)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[3]		7.6	0.181	1,387	0.69
Nitrogen Oxides (NOx)		100.0	2.38	18,249	9.12
Sulfur Oxides		0.6	0.014	109	0.05
Carbon Monoxide (CO)		84.0	2.00	15,329	7.66
VOC		5.5	0.131	1,004	0.50
Lead		0.0005	1.19E-05	9.12E-02	4.56E-05

Notes:

1 Maximum Firing Rate calculated from Manufacture Boiler Rating (MMBTu/hr) and the Natural Gas heat value (Btu/scf) given by Intermountain Gas Company.

2 Criteria Pollutants (EPA AP-42, Section 1.4 Natural Gas Consumption, Tables 1.4-1 and 1.4-2).

3 PM emission factor is assumed to equal PM_{10}.

Glanbia Gooding Cheese-Whey Facility (Boiler 2 burning No. 2 fuel oil)

Boiler (MMBtu/hr)	**25.1**	1992 Cleaver Brooks
Model No.		
Fuel Type	**Distillate #2**	
Maximum sulfur content (0.05%)	**0.05**	
Maximum Firing Rate (gals/hr)[1]	**179.3**	
Maximum Heat Input Rating (Btu/hr)	**25,100,000**	
Maximum Operation Limit (hrs/yr)	**1,080**	
Maximum Firing Rate (gals/yr)	**193,629**	
Heat Value of Fuel (Btu/gal)	**140,000**	

			Uncontrolled Potential to Emit[2]		
Criteria Pollutant[3]	**CAS No.**	**Emission Factor (lb/Mgal)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[4]		2.0	0.36	387.3	1.94E-01
Nitrogen Oxides (NOx)		20.0	3.59	3,872.6	1.94E+00
Sulfur Oxides[5]		7.1	1.27	1,374.8	6.87E-01
Carbon Monoxide (CO)		5.0	0.90	968.1	4.84E-01
TOC[6]		0.556	0.10	107.7	5.38E-02

			Uncontrolled Potential to Emit				
Toxic Air Pollutants[7]	**CAS No.**	**Emission Factor (lb/Mgal)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**	**IDAPA 58.01.01.585/586 - EL (lb/hr)**	**PTE Emission Rate vs. EL**
Benzene	71-43-2	2.14E-04	3.84E-05	4.14E-02	2.07E-05	8.00E-04	Below
Ethyl Benzene	100-41-4	6.36E-05	1.14E-05	1.23E-02	6.16E-06	2.90E+01	Below
Naphthalene	91-20-3	1.13E-03	2.03E-04	2.19E-01	1.09E-04	3.33E+00	Below
Methyl Chloroform[8]	71-55-6	2.36E-04	4.23E-05	4.57E-02	2.28E-05	1.27E+02	Below
Toluene	108-88-3	6.20E-03	1.11E-03	1.20E+00	6.00E-04	2.50E+01	Below
o-Xylenes	1330-20-7	1.09E-04	1.95E-05	2.11E-02	1.06E-05	2.90E+01	Below
POM[9]		3.30E-03	5.92E-04	6.39E-01	3.19E-04	2.00E-06	**Exceeds**

			Uncontrolled Potential to Emit				
Toxic Air Pollutants-Metals[10]	**CAS Number**	**Emission Factor ($lb/10^{12}Btu$)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**	**IDAPA 58.01.01.585/586 - EL (lb/hr)**	**PTE Emission Rate vs. EL**
Arsenic	7440-38-2	4.00E+00	1.00E-04	1.08E-01	5.42E-05	1.50E-06	**Exceeds**
Beryllium	7440-41-7	3.00E+00	7.53E-05	8.13E-02	4.07E-05	2.80E-05	**Exceeds**
Cadmium	7440-43-9	3.00E+00	7.53E-05	8.13E-02	4.07E-05	3.70E-06	**Exceeds**
Chromium	7440-47-3	3.00E+00	7.53E-05	8.13E-02	4.07E-05	5.60E-07	**Exceeds**
Copper	7440-50-8	6.00E+00	1.51E-04	1.63E-01	8.13E-05	1.30E-02	Below
Lead	7439-92-1	9.00E+00	2.26E-04	2.44E-01	1.22E-04	#N/A	
Manganese	7439-96-5	6.00E+00	1.51E-04	1.63E-01	8.13E-05	6.70E-02	Below
Mercury	7439-97-6	3.00E+00	7.53E-05	8.13E-02	4.07E-05	1.00E-03	Below
Nickel	7440-02-0	3.00E+00	7.53E-05	8.13E-02	4.07E-05	2.75E-05	**Exceeds**
Selenium	7782-49-2	1.50E+01	3.77E-04	4.07E-01	2.03E-04	1.30E-02	Below
Zinc	1314-13-2	4.00E+00	1.00E-04	1.08E-01	5.42E-05	3.33E-01	Below

Notes:

[1] Maximum Firing Rate calculated from Manufacture Boiler Rating (MMBTu/hr) and the Distillate #2 heat value (Btu/gal) given in EPA AP-42, Appendix A, Typical Parameters of Various Fuels).

[2] Uncontrolled potential emissions are based on the permit limit of 500,000 gallons of fuel used per year (250,000 used - assume even split between 2 Boilers for estimating emissions only).

[3] Criteria Pollutants, small boilers (EPA AP-42, Section 1.3 Fuel Oil Combustion, Tables 1.3-1 and 1.3-3).

[4] PM emission factor is assumed to equal PM_{10}.

[5] SO_2 emission factor multiplied by percent sulfur content of fuel (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-1).

[6] TOC emission factor is used to estimate VOCs (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-3)

[7] Toxic Air Pollutants (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-9).

[8] Methyl Chloroform synonym 1,1,1-Trichloroethane.

[9] Polycyclic Organic Matter is the sum of benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, indeno(1,2,3-cd)pyrene, and benzo(a)pyrene.

[10] Trace elements from distillate fuel oil combustion sources (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-10).

Glanbia Gooding Cheese-Whey Facility (Boiler 3 burning Natural Gas)

Boiler (MMBtu/hr)	**25.1**	1996 Cleaver Brooks
Model No.		
Fuel Type	**Natural Gas**	
Maximum Firing Rate (MMcf/hr)[1]	**2.38E-02**	
Maximum Operation Limit (hrs/yr)	**7,680**	8760- max hrs on diesel (see diesel spreadsheet)
Maximum Firing Rate (MMcf/yr)	**182**	
Heat Value of Fuel (Btu/scf)	**1,056**	

			Uncontrolled Potential to Emit		
Criteria Pollutant[2]	**CAS No.**	**Emission Factor ($lb/10^6$ scf)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[3]		7.6	0.181	1,387	0.69
Nitrogen Oxides (NOx)		100.0	2.38	18,249	9.12
Sulfur Oxides		0.6	0.014	109	0.05
Carbon Monoxide (CO)		84.0	2.00	15,329	7.66
VOC		5.5	0.131	1,004	0.50
Lead		0.0005	1.19E-05	9.12E-02	4.56E-05
			Uncontrolled Potential to Emit		

Notes:

[1] Maximum Firing Rate calculated from Manufacture Boiler Rating (MMBTu/hr) and the Natural Gas heat value (Btu/scf) given by Intermountain Gas Company.

[2] Criteria Pollutants (EPA AP-42, Section 1.4 Natural Gas Consumption, Tables 1.4-1 and 1.4-2).

[3] PM emission factor is assumed to equal PM_{10}.

Glanbia Gooding Cheese-Whey Facility (Boiler 3 burning No. 2 fuel oil)

Boiler (MMBtu/hr)	25.1	1996 Cleaver Brooks
Model No.		
Fuel Type	Distillate #2	
Maximum sulfur content (0.05%)	0.05	
Maximum Firing Rate (gals/hr)[1]	179.3	
Maximum Heat Input Rating (Btu/hr)	25,100,000	
Maximum Operation Limit (hrs/yr)	1,080	
Maximum Firing Rate (gals/yr)	193,629	
Heat Value of Fuel (Btu/gal)	140,000	

			Uncontrolled Potential to Emit[2]		
Criteria Pollutant[3]	CAS No.	Emission Factor (lb/Mgal)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)
Total Particulate Matter (PM)[4]		2.0	0.36	387.3	1.94E-01
Nitrogen Oxides (NOx)		20.0	3.59	3,872.6	1.94E+00
Sulfur Oxides[5]		7.1	1.27	1,374.8	6.87E-01
Carbon Monoxide (CO)		5.0	0.90	968.1	4.84E-01
TOC[6]		0.556	0.10	107.7	5.38E-02

			Uncontrolled Potential to Emit				
Toxic Air Pollutants[7]	CAS No.	Emission Factor (lb/Mgal)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	IDAPA 58.01.01.585/5 86 - EL (lb/hr)	PTE Emission Rate vs. EL
Benzene	71-43-2	2.14E-04	3.84E-05	4.14E-02	2.07E-05	8.00E-04	Below
Ethyl Benzene	100-41-4	6.36E-05	1.14E-05	1.23E-02	6.16E-06	2.90E+01	Below
Naphthalene	91-20-3	1.13E-03	2.03E-04	2.19E-01	1.09E-04	3.33E+00	Below
Methyl Chloroform[8]	71-55-6	2.36E-04	4.23E-05	4.57E-02	2.28E-05	1.27E+02	Below
Toluene	108-88-3	6.20E-03	1.11E-03	1.20E+00	6.00E-04	2.50E+01	Below
o-Xylenes	1330-20-7	1.09E-04	1.95E-05	2.11E-02	1.06E-05	2.90E+01	Below
POM[9]		3.30E-03	5.92E-04	6.39E-01	3.19E-04	2.00E-06	Exceeds

			Uncontrolled Potential to Emit				
Toxic Air Pollutants-Metals[10]	CAS Number	Emission Factor (lb/10^{12}Btu)	Emission Rate (lb/hr)	Emission Rate (lb/yr)	Emission Rate (ton/yr)	IDAPA 58.01.01.585/5 86 - EL (lb/hr)	PTE Emission Rate vs. EL
Arsenic	7440-38-2	4.00E+00	1.00E-04	1.08E-01	5.42E-05	1.50E-06	Exceeds
Beryllium	7440-41-7	3.00E+00	7.53E-05	8.13E-02	4.07E-05	2.80E-05	Exceeds
Cadmium	7440-43-9	3.00E+00	7.53E-05	8.13E-02	4.07E-05	3.70E-06	Exceeds
Chromium	7440-47-3	3.00E+00	7.53E-05	8.13E-02	4.07E-05	5.60E-07	Exceeds
Copper	7440-50-8	6.00E+00	1.51E-04	1.63E-01	8.13E-05	1.30E-02	Below
Lead	7439-92-1	9.00E+00	2.26E-04	2.44E-01	1.22E-04	#N/A	
Manganese	7439-96-5	6.00E+00	1.51E-04	1.63E-01	8.13E-05	6.70E-02	Below
Mercury	7439-97-6	3.00E+00	7.53E-05	8.13E-02	4.07E-05	1.00E-03	Below
Nickel	7440-02-0	3.00E+00	7.53E-05	8.13E-02	4.07E-05	2.75E-05	Exceeds
Selenium	7782-49-2	1.50E+01	3.77E-04	4.07E-01	2.03E-04	1.30E-02	Below
Zinc	1314-13-2	4.00E+00	1.00E-04	1.08E-01	5.42E-05	3.33E-01	Below

Notes:

[1] Maximum Firing Rate calculated from Manufacture Boiler Rating (MMBTu/hr) and the Distillate #2 heat value (Btu/gal) given in EPA AP-42, Appendix A, Typical Parameters of Various Fuels).

[2] Uncontrolled potential emissions are based on the permit limit of 500,000 gallons of fuel used per year (250,000 used - assume even split between 2 Boilers for estimating emissions only).

[3] Criteria Pollutants, small boilers (EPA AP-42, Section 1.3 Fuel Oil Combustion, Tables 1.3-1 and 1.3-3).

[4] PM emission factor is assumed to equal PM_{10}.

[5] SO_2 emission factor multiplied by percent sulfur content of fuel (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-1).

[6] TOC emission factor is used to estimate VOCs (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-3)

[7] Toxic Air Pollutants (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-9).

[8] Methyl Chloroform synonym 1,1,1-Trichloroethane.

[9] Polycyclic Organic Matter is the sum of benzo(a)anthracene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, indeno(1,2,3-cd)pyrene, and benzo(a)pyrene.

[10] Trace elements from distillate fuel oil combustion sources (EPA AP-42, Section 1.3 Fuel Oil Combustion, Table 1.3-10).

Glanbia Gooding Cheese-Whey Facility (Boiler 4 burning Natural Gas)

Boiler (MMBtu/hr)	**25.1**	1999 Cleaver Brooks
Model No.		
Fuel Type	**Natural Gas**	
Maximum Firing Rate (MMcf/hr)[1]	**2.38E-02**	
Maximum Operation Limit (hrs/yr)	**8,760**	
Maximum Firing Rate (MMcf/yr)	**208**	
Heat Value of Fuel (Btu/scf)	**1,056**	

			Uncontrolled Potential to Emit		
Criteria Pollutant[2]	**CAS No.**	**Emission Factor ($lb/10^6$ scf)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[3]		7.6	0.181	1,582	0.79
Nitrogen Oxides (NOx)		100.0	2.38	20,816	10.41
Sulfur Oxides		0.6	0.014	125	0.06
Carbon Monoxide (CO)		84.0	2.00	17,485	8.74
VOC		5.5	0.131	1,145	0.57
Lead		0.0005	1.19E-05	1.04E-01	5.20E-05

Notes:

[1] Maximum Firing Rate calculated from Manufacture Boiler Rating (MMBTu/hr) and the Natural Gas heat value (Btu/scf) given by Intermountain Gas Company.

[2] Criteria Pollutants (EPA AP-42, Section 1.4 Natural Gas Consumption, Tables 1.4-1 and 1.4-2).

[3] PM emission factor is assumed to equal PM_{10}.

Glanbia Gooooding Cheese Facility (WPC Dryer)

Boiler (MMBtu/hr)*	**9.2**
Model No.	
Fuel Type	**Natural Gas**
Maximum Heat Input Rating (Btu/hr)	**9,200,000**
Maximum Operation Limit (hrs/yr)	**8,760**
Heat Value of Fuel (Btu/scf)	**1,056**
Natural Gas Flow (scf/hr)	**8,710**

			Uncontrolled Potential to Emit		
Criteria Pollutant[1]	**CAS No.**	**Emission Factor ($lb/10^6$ scf)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[2]		7.6	6.62E-02	5.80E+02	2.90E-01
Nitrogen Oxides (NOx)		100.0	8.71E-01	7.63E+03	3.81E+00
Sulfur Oxides		0.6	5.23E-03	4.58E+01	2.29E-02
Carbon Monoxide (CO)		84.0	7.32E-01	6.41E+03	3.20E+00
VOC		5.5	4.79E-02	4.20E+02	2.10E-01
Lead		0.0005	4.35E-06	3.81E-02	1.91E-05

Notes:

[1]Criteria Air Pollutants (EPA AP-42, Section 1.4 Natural Gas Combustion, Table 1.4-2).

[2] PM emission factor is assumed to equal PM_{10}.

Glanbia Gooding Cheese-Whey Facility (Generator)

Generator Name	**Cummins**
Model No.	**Standby**
Engine Power Rating (kW)	815
Engine Power Rating (hp)	1,093
Fuel Type	Diesel
- maximum sulfur content (%)	0.5
Maximum Firing Rate (gals/hr)	40.7
Maximum Heat Input Rating (Btu/hr)	5,698,000
Maximum Hours of Operation	200
Maximum Firing Rate (gals/yr)	8,140
Annual Operation Limit (hrs/yr)	200
Annual Firing Rate (gals/yr)	8,140
Heat Value of Fuel (Btu/gal)	140,000

			Uncontrolled Potential to Emit		
Pollutant	**CAS No.**	**Emission Factor (lb/MMBtu)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[1]		0.1	0.57	114	0.06
Nitrogen Oxides (NOx)		3.2	18.23	3,647	1.82
Sulfur Oxides[2]		0.51	2.88	575	0.29
Carbon Monoxide (CO)		0.85	4.84	969	0.48
HC[3]		0.09	0.51	103	0.05
Lead[4]	7439-92-1	9.00	5.13E-05	0.01	5.13E-06

Notes:

AP-42 emission factors were utilized to estimate emissions for particulate matter (PM), oxides of nitrogen (NOx), sulfur oxides (SOx), carbon monoxide (CO), and hydrocarbons (HC) in lieu of volatile organic compounds (VOCs).

[1] PM emission factor is assumed to equal PM_{10}.

[2] SO_2 emission factor multiplied by percent sulfur content of fuel (EPA AP-42 Table 3.4-1)

[3] HC emission factor is used to estimate VOCs.

[4] Lead emission factor is based on $lb/10^{12}$ Btu

Glanbia Gooooding Cheese-Whey Facility (Natural Gas Heater 1)

Boiler (MMBtu/hr)*	**1.5**
Model No.	**Reznor**
Fuel Type	**Natural Gas**
Maximum Firing Rate (MMcf/hr)	**NA**
Maximum Heat Input Rating (Btu/hr)	**1,500,000**
Maximum Operation Limit (hrs/yr)	**8,760**
Maximum Firing Rate (MMcf/yr)	**NA**
Heat Value of Fuel (Btu/scf)	**1,056**
Natural Gas Flow (scf/hr)	**1,420**

			Uncontrolled Potential to Emit		
Criteria Pollutant[1]	**CAS No.**	**Emission Factor ($lb/10^6$ scf)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[2]		7.6	1.08E-02	9.45E+01	4.73E-02
Nitrogen Oxides (NOx)		100.0	1.42E-01	1.24E+03	6.22E-01
Sulfur Oxides		0.6	8.52E-04	7.46E+00	3.73E-03
Carbon Monoxide (CO)		84.0	1.19E-01	1.04E+03	5.22E-01
VOC		5.5	7.81E-03	6.84E+01	3.42E-02
Lead		0.0005	7.10E-07	6.22E-03	3.11E-06

Notes:

[1] Criteria Pollutants (EPA AP-42, Section 1.4 Natural Gas Consumption, Tables 1.4-1 and 1.4-2).

[2] PM emission factor is assumed to equal PM_{10}.

Glanbia Gooooding Cheese-Whey Facility (Natural Gas Heater 2)

Boiler (MMBtu/hr)*	**5.89**
Model No.	
Fuel Type	**Natural Gas**
Maximum Firing Rate (MMcf/hr)	**NA**
Maximum Heat Input Rating (Btu/hr)	**5,890,000**
Maximum Operation Limit (hrs/yr)	**8,760**
Maximum Firing Rate (MMcf/yr)	**NA**
Heat Value of Fuel (Btu/scf)	**1,056**
Natural Gas Flow (scf/hr)	**5,576**

			Uncontrolled Potential to Emit		
Criteria Pollutant[1]	**CAS No.**	**Emission Factor ($lb/10^6$ scf)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[2]		7.6	4.24E-02	3.71E+02	1.86E-01
Nitrogen Oxides (NOx)		100.0	5.58E-01	4.88E+03	2.44E+00
Sulfur Oxides		0.6	3.35E-03	2.93E+01	1.47E-02
Carbon Monoxide (CO)		84.0	4.68E-01	4.10E+03	2.05E+00
VOC		5.5	3.07E-02	2.69E+02	1.34E-01
Lead		0.0005	2.79E-06	2.44E-02	1.22E-05

Notes:

[1] Criteria Pollutants (EPA AP-42, Section 1.4 Natural Gas Consumption, Tables 1.4-1 and 1.4-2).

[2] PM emission factor is assumed to equal PM_{10}.

Glanbia Gooooding Cheese-Whey Facility (Natural Gas Heater 3)

Boiler (MMBtu/hr)*	**1.374**
Model No.	
Fuel Type	**Natural Gas**
Maximum Firing Rate (MMcf/hr)	**NA**
Maximum Heat Input Rating (Btu/hr)	**1,374,000**
Maximum Operation Limit (hrs/yr)	**8,760**
Maximum Firing Rate (MMcf/yr)	**NA**
Heat Value of Fuel (Btu/scf)	**1,056**
Natural Gas Flow (scf/hr)	**1,301**

			Uncontrolled Potential to Emit		
Criteria Pollutant[1]	**CAS No.**	**Emission Factor ($lb/10^6$ scf)**	**Emission Rate (lb/hr)**	**Emission Rate (lb/yr)**	**Emission Rate (ton/yr)**
Total Particulate Matter (PM)[2]		7.6	9.89E-03	8.66E+01	4.33E-02
Nitrogen Oxides (NOx)		100.0	1.30E-01	1.14E+03	5.70E-01
Sulfur Oxides		0.6	7.80E-04	6.84E+00	3.42E-03
Carbon Monoxide (CO)		84.0	1.09E-01	9.57E+02	4.79E-01
VOC		5.5	7.15E-03	6.27E+01	3.13E-02
Lead		0.0005	6.50E-07	5.70E-03	2.85E-06

Notes:

[1] Criteria Pollutants (EPA AP-42, Section 1.4 Natural Gas Consumption, Tables 1.4-1 and 1.4-2).

[2] PM emission factor is assumed to equal PM_{10}.

Table G-1 **Compliance with IDAPA Rule 676 PM Standard for Fuel Burning Equipment**				
Unit	Nos. 2 and 3 Dual-Fueled Boilers		Biogas Boiler	
Fuel	Natural Gas	No. 2 Fuel Oil	Biogas	Natural Gas
Rated Heat Input (MM Btu/hr)	25.1		16.74	
PM Emission Rate (lb/hr)	0.18	0.36	0.12	0.05
Exit/Flue Gas Flowrate Calculation				
F_d (Table 19-2, EPA Method 19) (dscf/MM Btu) [1,2]	8,710	9,190	8,710	8,710
Exit flowrate @ 0% O_2: (dscfm)	3,644	3,844	2,430	2,430
Exit flowrate @ 3% O_2: (dscfm) [3]	4,254	4,489	2,837	2,837
Calculated Grain Loading (gr/dscf @ 3% O_2) [4]	0.005	0.009	0.005	0.002
PM Loading Standard (IDAPA 58.01.01.676) (gr/dscf @ 3% 02) (0.015 for gas, 0.05 for liquid)	0.015	0.050	0.015	0.015
Compliance w/ PM Loading Standard	**Yes**	**Yes**	**Yes**	**Yes**

[1] Appendix A-7 to 40 CFR part 60, Method 19—Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates, Table 19-2 (F Factors for Various Fuels).

[2] F_d, Volumes of combustion components per unit of heat content (scf/million Btu). On a Btu basis, F_d for all gaseous fuels (i.e., natural gas, propane, and butane) is identical (8,710 dscf/ MM Btu). F_d for biogas (which is primarily methane, or natural gas) was set at 8,710 dscf/MM Btu.

[3] $(\text{Flow}_{3\%}) = (\text{Flow}_{0\%}) \times (20.9/(20.9 - 3))$, where 20.9 = Oxygen concentration in ambient air

[4] (Flow (dscfm) x (7,000 gr/lb) x (PM lb/hr) x (60 min/ hr) = gr/dscf.

SO2 rate LB/hr
SO2 CF/min
SO2 Conc ppm
SO2 Conc ppm @3%O2

Table G-2 **Compliance with IDAPA Rule 786 PM Standard for Incineration**	
Biogas combustion rate (scfm) [1]	301
Biogas methane content	65%
Methane density (lb/ft^3) [2]	0.0448
Hourly methane combustion rate ("refuse" lb/hr) [3]	526
Flare PM emission rate (lb/hr) [1]	0.085
PM emission rate (lb PM/lb refuse)	0.0001606
PM emission rate (lb PM/ 100 lb refuse)	0.01606
IDAPA 58.01.01.786.01 standard (lb PM / 100 lb refuse)	0.2
Compliance with IDAPA standard	Yes

[1] See flare emission calculations

[2] Perry's Chemical Engineers' Handbook, Sixth Edition, Table 3-20

[3] (Biogas combustion (scfm)) x (60 min/hr) x (methane %)

Appendix A-7 to 40 CFR part 60
Method 19—Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates,
Table 19-1 (Conversion factors for Concentration)

From	To	Multiply by
g/scm	ng/scm	10\9\
mg/scm	ng/scm	10\6\
lb/scf	ng/scm	1.602 x 10\13\
ppm SO2	ng/scm	2.66 x 10\6\
ppm NOX	ng/scm	1.912 x 10\6\
ppm SO2	lb/scf	1.660 x 10-7
ppm NOX	lb/scf	1.194 x 10-7

Appendix A-7 to 40 CFR part 60
Method 19—Determination of sulfur dioxide removal efficiency and particulate, sulfur dioxide and nitrogen oxides emission rates,
Table 19-2 (F Factors for Various Fuels) \1

Fuel Type	Fd		Fw		Fc	
	dscm/J	dscf/10\6\ Btu	wscm/J	wscf/10\6\ Btu	scm/J	scf/10\6\ Btu
Coal:						
Anthracite 2	2.71x10-7	10,100	2.83x10-7	10,540	0.530x10-7	1,970
Bituminus 2	2.63x10-7	9,780	2.86x10-7	10,640	0.484x10-7	1,800
Lignite	2.65x10-7	9,860	3.21x10-7	11,950	0.513x10-7	1,910
Oil \3\	2.47x10-7	9,190	2.77x10-7	10,320	0.383x10-7	1,420
Gas:						
Natural	2.34x10-7	8,710	2.85x10-7	10,610	0.287x10-7	1,040
Propane	2.34x10-7	8,710	2.74x10-7	10,200	0.321x10-7	1,190
Butane	2.34x10-7	8,710	2.79x10-7	10,390	0.337x10-7	1,250
Wood	2.48x10-7	9,240			0.492x10-7	1,830
Wood Bark	2.58x10-7	9,600			0.516x10-7	1,920
Municipal	2.57x10-7	9,570			0.488x10-7	1,820
Solid Waste						

\1\ Determined at standard conditions: 20 °C (68 °F) and 760 mm Hg (29.92 in Hg)

\2\ As classified according to ASTM D 388.

\3\ Crude, residual, or distillate.

Appendix C

Modeling Review

P-040404

MODELING MEMORANDUM

DATE: May 23, 2005

TO: Darrin Mehr, Permit Writer

THROUGH: Kevin Schilling, Stationary Source Modeling Coordinator

FROM: Almer Casile, Permitting Analyst

PROJECT NUMBER: P-040404

SUBJECT: Modeling Review for the Glanbia Inc, Gooding
Facility ID No. 047-00008

1.0 Summary

Atmospheric dispersion modeling of emissions was submitted in a permit to construct application for the installation of a biogas boiler and flare, and the modification of process boilers at Glanbia's Gooding Idaho facility. Atmospheric dispersion modeling was submitted to demonstrate that the proposed project would not cause or significantly contribute to a violation of any ambient air quality standard (IDAPA 58.01.01.203.02). This modeling analysis includes nine sources, and addressed the criteria pollutants sulfur dioxide (SO_2), and seven toxic air pollutants (TAPs). The TAPs include: arsenic, benzene, beryllium, cadmium, formaldehyde, nickel, and total PAH.

Table 1 presents the key assumptions used in the modeling analysis submitted by the applicant.

Table 1: KEY ASSUMPTIONS USED IN MODELING ANALYSIS SUBMITTED BY THE APPLICANT

Assumption	Explanation
The pound per hour criteria pollutant emission rates used to determine compliance with ambient air quality standards with averaging periods shorter than annual differed from the pound per hour criteria emission rates used to determine compliance with annual ambient air quality standards.	The facility has proposed short term operating scenarios different than those used on an annual basis to account for worst case short term emissions.
TAP emissions from Boiler 2, Boiler 3, Boiler 5, and Flare were used to determine compliance with the TAP AACC standards.	Facility has provided an overly conservative method for demonstrating compliance with the standards for TAPs.

Based on the results of the analysis, DEQ has determined that the submitted modeling analysis demonstrates, to DEQ's satisfaction, that the facility will not cause or significantly contribute to a violation of any ambient air quality standards of SO_2. Impacts of TAPs were all below allowable increments of IDAPA 58.01.01.585 and 586.

2.0 Background Information

2.1 Applicable Air Quality Impact Limits

This facility is located in Gooding County which is designated as an attainment or unclassifiable area for sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), lead (Pb), ozone (O_3), and particulate matter with an aerodynamic diameter less than or equal to a nominal 10 micrometers (PM_{10}).

The application proposes changes in emissions that exceed modeling thresholds for SO_2, and the TAP screening levels for: arsenic, benzene, beryllium, cadmium, formaldehyde, nickel, total PAH. The applicable regulatory limits for the application are presented in Table 2.

Table 2: APPLICABLE REGULATORY LIMITS

Pollutant	Averaging Period	Modeling Threshold[a, e]	Regulatory Limit ($\mu g/m^3$)[b, c]	Modeled Value Used[d]
SO_2	3-hour	1 tpy or 0.2 lb/hr	1,300	Highest 2nd highest
	24-hour		365	Highest 2nd highest
	Annual		80	Maximum 1st highest
Arsenic	Annual	1.5E-06 $\mu g/m^3$	2.3E-04	Maximum 1st highest
Benzene	Annual	8.0E-04 $\mu g/m^3$	1.2E-01	Maximum 1st highest
Beryllium	Annual	2.8E-05 $\mu g/m^3$	4.2E-03	Maximum 1st highest
Cadmium	Annual	3.7E-06 $\mu g/m^3$	5.6E-04	Maximum 1st highest
Formaldehyde	Annual	5.1E-04 $\mu g/m^3$	7.7E-02	Maximum 1st highest
Nickel	Annual	2.7E-05 $\mu g/m^3$	4.2E-03	Maximum 1st highest
Total PAH	Annual	9.1E-05 $\mu g/m^3$	1.4E-02	Maximum 1st highest

[a] IDAPA 58.01.01.006.93

[b] Micrograms per cubic meter

[c] IDAPA 58.01.01.577 for criteria pollutants, IDAPA 58.01.01.585 for non-carcinogenic toxic air pollutants IDAPA 58.01.01.586 for carcinogenic toxic air pollutants.

[d] The maximum 1st highest modeled value is always used for significant impact analysis and for all toxic air pollutants. Concentration at any modeled receptor.

[e] Toxic air pollutant modeling thresholds represent the EL from IDAPA 58.01.01.585 for non-carcinogenic toxic air pollutants IDAPA 58.01.01.586 for carcinogenic toxic air pollutants.

2.2 *Background Concentrations*

The appropriate background concentrations for this modeling analysis were provided by DEQ in its October 2004 review of the modeling protocol. The concentrations are presented in Table 3.

Table 3: BACKGROUND CONCENTRATIONS

Pollutant	Averaging Period	Background concentrations ($\mu g/m^3$)[a,b]
SO_2	3-hour	34
	24-hour	24
	Annual	8

[a] Micrograms per cubic meter.

[b] Based on statewide default background concentrations for rural/agricultural areas

3.0 Assessment of Submitted, Certified Modeling Analysis

This section documents the assessment of the application materials as submitted and certified by the applicant.

3.1 *Modeling Methodology*

CH_2M Hill conducted the modeling analysis. Table 4 presents the modeling assumptions and parameters used by the applicant. Table 4 also includes DEQ's review and determination of those assumptions and parameters.

Table 4: MODELING PARAMETERS

Parameter	What Facility Submitted	DEQ's Review/Determination
Modeling protocol	A modeling protocol was submitted for prior approval, and a meeting held discussing the application.	The protocol was followed.
Model Selection	ISC-Prime version 04269	This version was used to review the submitted files and to account for downwash.
Meteorological Data	Boise 1987 through 1991 data	Appropriate
Model Options	Regulatory defaults used	Appropriate
Land Use	Rural land use	Appropriate
Complex Terrain	Simple and complex terrain is included in the model	Appropriate
Building Downwash	Downwash was included	Appropriate
Receptor Network	25 meter on fence line 100 meters out to 1000 meters 500 meters out to 5000 meters	This is sufficient to adequately resolve the maximum design concentration
Facility Layout	Plot Plan	The facility building layout used in the model was verified by using the scaled plot plan submitted by the applicant. Exhausts locations were verified against updated information submitted by the facility. A discrepancy was noted in the location of Boilers 1-4. After discussion with CH2M Hill, the locations of the boilers, as provided in the model, were used as the default.

3.2 Emission Rates

Table 5a, 5b and 5c provide the criteria pollutant and TAPs emission rates used in the submitted modeling files. Table 5a contains the emissions rates used for all modeling runs with averaging periods less than 1 year. Table 5b contains the emission rates used for all modeling runs with annual average periods. Table 5c contains the emission rates for all modeling runs of TAPs with an annual averaging period.

Table 5a: EMISSION RATES FOR SO_2 FOR AVERAGING PERIODS UNDER 1 YEAR

Source	Emission Rates (lb/hr)[a]
	SO_2
Boiler 1	0.02
Boiler 2	1.27
Boiler 3	1.27
Boiler 4	1.40E-02
Boiler 5	6.87
Flare	0.0
Generator	2.88
Dryer	5.23E-02
Heaters	5.00E-03

[a] Pounds per hour.

Table 5b: EMISSION RATES FOR SO_2 FOR ANNUAL AVERAGING PERIOD

Source	Emission Rates (lb/hr)[a]
	SO_2
Boiler 1	0.016
Boiler 2	0.17
Boiler 3	0.17
Boiler 4	0.014
Boiler 5	6.87
Flare	0.0
Generator	6.62E-02
Dryer	5.23E-03
Heaters	3.88E-03

[a] Pounds per hour.

Table 5c: EMISSION RATES FOR TOXIC POLLUTANTS FOR ANNUAL AVERAGING PERIOD

Source	Emission Rates (lb/hr)							
	Arsenic	Benzene	Beryllium	Cadmium	Formaldehyde	Nickel	POM	Total PAH
Boiler 2	1.24E-05	4.73E-06	9.29E-06	9.29E-06	0.0	9.29E-06	7.28E-05	0.0
Boiler 3	1.24E-05	4.73E-06	9.29E-06	9.29E-06	0.0	9.29E-06	7.28E-05	0.0
Boiler 5	2.22E-06	1.05E-03	1.33E-07	1.22E-05	8.33E-04	2.33E-05	0.0	7.24E-06
Flare	0.0	2.88E-03	0.0	0.0	2.11E-02	0.0	0.0	2.53E-04

3.3 Emission Release Parameters

The emission release parameters used in the modeling analysis submitted by the applicant are presented in Table 6a and 6b.

Table 6a: POINT SOURCE EMISSION RELEASE PARAMETERS

Source	Stack Exhaust Type	Stack Height (ft)	Temp (°F)	Exit Velocity (ft/s)	Stack Diameter (ft)
Boiler 1	Vertical	31	350.01	42.44	2
Boiler 2	Vertical	31	370	42.44	2
Boiler 3	Vertical	31	370	42.44	2
Boiler 4	Vertical	31	478.29	32.12	2.5
Boiler 5	Vertical	21	325	43.83	2
Flare[a]	Vertical	26.6	1400	40	0.67
Generator	Vertical	14	891.10	169	1.33
Dryer	Vertical	84	165	77.5	3.28

[a] Release height calculated according to methodology in Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, EPA 1992

Table 6b: VOLUME SOURCE EMISSION RELEASE PARAMETERS

Source	Easting (ft)	Northing (ft)	Release Height (ft)	Horizontal Dimension[a] (ft)	Vertical Dimension[b] (ft)
Heaters	2273917	15609724	29.99	1.02	13.94

[a] Horizontal dimension σ_{yo} equals width divided by 4.3, where width equals 4.41 ft.

[b] Vertical dimension σ_{zo} equals building height divided by 2.15, where building height equals 20 ft.

3.4 Results

This section present the results based on the information submitted as certified by the applicant.

3.4.1 Full Impact Analysis Results

As provided in the application, facility-wide SO_2 pollutant emissions exceeded modeling threshold values given in *Air Quality Modeling Guideline (rev. 12/31/02).* A significant impact analysis, therefore, was not conducted, and a full impact analysis was conducted. SO_2 pollutant emissions were modeled and the results are included in the following table.

Table 7: FACILITY CONCENTRATIONS FOR CRITERIA POLLUTANTS FOR FULL IMPACT ANALYSIS

Pollutant	Averaging Period	Facility Ambient Concentration ($\mu g/m^3$)[a]	Total Ambient concentration[b] ($\mu g/m^3$)[a]	Percent of NAAQS[c]
SO_2	3-hour	323	357	27
	24-hour	150	174	47
	Annual	45	53	66

[a] Micrograms per cubic meter.
[b] Includes background concentration and facility impact.
[c] National Ambient Air Quality Standard

3.4.2 Toxic Air Pollutants Results

Though Boiler 5 is the only new equipment to be installed with this proposed permitting action, TAP emissions from boilers 2 and 3, and the flare, were also modeled. The maximum concentrations given below, therefore, are conservative because of the inclusion of the emissions from those additional sources.

Maximum concentration values are below AACC for each pollutant. The detailed results are in the following table.

Table 8: TOXIC AIR POLLUTANTS ANALYSIS RESULTS

Pollutant	Averaging Period	Maximum Concentration ($\mu g/m^3$)	Regulatory Limit (ug/m^3)	Percent of Limit
Carcinogens				
Arsenic	Annual	1.3E-04	2.3E-04	57
Benzene	Annual	7.2E-02	1.2E-01	60
Beryllium	Annual	1.0E-04	4.2E-03	2
Cadmium	Annual	1.0E-04	5.6E-04	18
Formaldehyde	Annual	5.3E-02	7.7E-02	69
Nickel	Annual	1.5E-04	4.2E-03	4
Total PAH	Annual	6.3E-04	1.4E-02	4.5

Appendix D

EPA Region 10 Alternative Fuel Monitoring Determination

P-040404

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 10
1200 Sixth Avenue
Seattle, WA 98101

13 JUL 2005

Reply To
Attn Of: AWT - 107

Mr. Todd J. Hughes
Environmental Manager
Glanbia Foods Inc.
1728 South 2300 East
Gooding, Idaho 83330

Re: NSPS Subpart Dc Reduction in Fuel Use Record-Keeping Request

Dear Mr. Hughes:

This alternative fuel monitoring determination is in response to a request sent to the Environmental Protection Agency (EPA) by Glanbia Foods, Inc. (Glanbia) dated December 22, 2004. In this request, it is stated that Glanbia intends to maintain and operate five boilers, located at their facility in Gooding, Idaho. Four of these boilers are affected facilities subject to 40 CFR 60 Subpart Dc "Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units" (Subpart Dc) and also subject to certain general requirements of 40 CFR 60 Subpart A.

EPA approves the request from Glanbia for a reduction in the fuel usage record-keeping requirement in 40 CFR §60.48c of Subpart Dc from daily to monthly for Boilers 2, 3, and 4. EPA denies the reduction in the fuel usage record-keeping requirement in 40 CFR §60.48c for Boiler 5 and describes what is necessary in order to approve this for the biogas-fueled Boiler 5. EPA also approves the use of one gas meter to record monthly natural gas usage for Boilers 2, 3, and 4.

The five boilers at Glanbia's Gooding facility are of various sizes, fuels, and installation dates as follows:

- Boiler 1 is a 29.35 MMBtu/hr Continental E Series, fueled exclusively by natural gas and installed in 1979. Therefore, it is not subject to Subpart Dc, which has an applicability date of June 9, 1989.
- Boilers 2 and 3 are 25.1 MMBtu/hr Cleaver Brooks, duel-fired boilers, installed in 1992 and 1996, respectively. They operate on natural gas as the primary fuel with No. 2 diesel fuel as backup.
- Boiler 4 is also a 25.1 MMBtu/hr Cleaver Brooks boiler, but is fueled exclusively by natural gas and was installed in 1999.
- Boiler 5 is a 16.7 MMBtu/hr Cleaver Brooks boiler. It is fueled by biogas from the Wastewater Treatment effluent process as the primary fuel and can burn natural gas as a backup. It was installed in February 2005.

Glanbia has requested to reduce the record-keeping requirement of 40 CFR §60.48c. They request approval to record the amount of each fuel combusted in Boilers 2-5 during each month instead of during each day as required by Subpart Dc. Boiler 5 is in a separate building from Boilers 1-4 and Boiler 5 will have a separate natural gas and biogas meter to measure the fuel used by Boiler 5 on a monthly basis. Glanbia proposes to have one gas meter for Boilers 2, 3, and 4 that will measure the total natural gas usage per month. When more than one boiler is firing natural gas simultaneously, they will divide each boiler design heat input capacity by the total of the design heat input capacities of each boiler, and use this to prorate the natural gas usage of each boiler on a monthly basis. For boilers 2 and 3, which are capable of firing low sulfur diesel fuel, each boiler will maintain individual fuel oil meters. EPA determines that this will adequately determine the fuel usage by each boiler.

The approval for the reduction in the record keeping to monthly instead of daily is based on a memorandum dated February 20, 1992, from the EPA Office of Air Quality Planning and Standards which states that

> There is little value in requiring daily record-keeping of the amounts of fuel combusted for an affected unit that fires only natural gas or natural gas with clean low-sulfur fuel oil (sulfur content less than 0.5%) as a backup.

EPA has approved requests for such units to maintain monthly, instead of daily, fuel records. EPA thus approves the reduction in record-keeping from daily to monthly for boilers 2-4 which fire only natural gas or natural gas with clean low-sulfur fuel oil (sulfur content less than 0.5%) as a backup. For units that fire oil there are additional certification requirements that the fuel oil sulfur limits of 0.5% are met. Therefore, EPA's approvals of monthly fuel use record-keeping for units that can fire oil have continued to require semi-annual reporting of excess emissions of the standards for sulfur dioxide, which are in 40 CFR § 60.42c(d) and § 60.42c(h)(1)), and required by 40 CFR § 60.48c(d). Those reports must be consistent with the general excess emissions reporting requirements of 40 CFR § 60.7(d).

Boiler 5 meets the basic applicability requirements of Subpart Dc based on the date of construction and the size, regardless of the fuel that is combusted, but similar to the use of natural gas, the use of biogas is not addressed with any requirements associated with the standards for sulfur dioxide or the standards for particulate matter, which are the only pollutants with standards in Subpart Dc. The record-keeping requirement of 40 CFR 60.48c(g) requires records of the amounts of <u>each fuel</u> combusted during each day (emphasis added). The decision to reduce this requirement for certain boilers is based on the assumption that that fuel has low sulfur content. The sulfur content of natural gas is well known, however, the use of biogas in the context of this regulation has not been addressed before and it is uncertain what the sulfur content of Glanbia's biogas is. After consultation with EPA headquarters Office of Enforcement and Compliance Assurance (OECA), EPA has concluded that the sulfur content of the biogas must be evaluated and determined to be less than 0.5% with little variability before the reduction in recordkeeping to Boiler 5 can be approved. Once the low sulfur content of the fuel has been demonstrated, the reduction in the record-keeping for Boiler 5 can be approved. Until then, 40 CFR 60.58c(g) must be followed for Boiler 5.

If you have any further questions or concerns, please contact Heather Valdez of the Region 10 Office of Air, Waste and Toxics at (206) 553-6220 or valdez.heather@epa.gov.

Sincerely,

Jeff KenKnight

Jeff KenKnight, Manager
Federal and Delegated Air Programs Unit
Office of Air, Waste and Toxics

cc: Bill Rogers, Idaho Department of Environmental Quality, Boise
Darrin Mehr, Idaho Department of Environmental Quality, Boise
Stephen VanZandt, Idaho Department of Environmental Quality, Twin Falls